APPLICATION FOR RENEWAL OF TITLE V AIR OPERATION PERMIT FT. PIERCE UTILITIES AUTHORITY

FORT PIERCE, FLORIDA

Prepared For:
Fort Pierce Utilities Authority
311 North Indian River Drive
Fort Pierce, Florida 34950

Prepared By:
Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

June 2007

07387523

DISTRIBUTION:
4 Copies – FDEP
2 Copies – Fort Pierce Utilities Authority
1 Copy – Golder Associates Inc.

FACILITY ID: 1110003

PROJECT #: 008

PERMIT TYPE: AV

PSD-FL-

PATS #:

DOCUMENT TYPE(S)/DATE:

✓ Application/ 6-25-07

__ Correspondence/

__ Intent/

__ Permit/

__ OGC/

__ Amendment/

Rescan ✓J

Comments:

Scan & keep with title V applications - thanks!

Scanned 6/28/07

APPLICATION FOR AIR PERMIT – LONG FORM

Department of Environmental Protection

RECEIVED
JUN 25 2007
BUREAU OF AIR REGULATION

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 at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air permit. Also use this form to apply for an air construction permit:

- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment area (NAA) new source review, or maximum achievable control technology (MACT) review; or
- Where the applicant proposes to assume a restriction on the potential emissions of one or more pollutants to escape a federal program requirement such as PSD review, NAA new source review, Title V, or MACT; or
- Where the applicant proposes 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/renewal Title V air operation permit.

Air Construction Permit & Title V Air Operation Permit (Concurrent Processing Option) – Use this form to apply for both an air construction permit and a revised or renewal Title V air operation permit incorporating the proposed project.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Ft. Pierce Utilities Authority**	
2. Site Name: **H. D. King Power Plant**	
3. Facility Identification Number: **1110003**	
4. Facility Location...: Street Address or Other Locator: **311 North Indian River Drive** City: **Ft. Pierce** County: **St. Lucie** Zip Code: **34950**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **John Tompeck, Planning Engineer**
2. Application Contact Mailing Address... Organization/Firm: **Ft. Pierce Utilities Authority** Street Address: **311 North Indian River Drive** City: **Ft. Pierce** State: **FL** Zip Code: **34950**
3. Application Contact Telephone Numbers... Telephone: **(772) 466-1600** ext. **5201** Fax: **(772) 465-7596**
4. Application Contact Email Address: **jtompeck@fpua.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 6-25-07	3. PSD Number (if applicable):
2. Project Number(s): 1110003-008-AV	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is 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

This application is for the renewal of the Title V Permit No. 1110003-005-AV for the H. D. King Power Plant, which expires on December 31, 2007.

Per permit No. 1110003-005-AV, the facility consists of one 16.5 MW (EU004), one 37.5 MW (EU007), and one 56.1 MW (EU008) fossil fuel-fired steam generators. The facility also has one 23.4 MW combined-cycle gas turbine with heat recovery steam generator (EU003). EU004 is in an extended shutdown situation. Ft. Pierce Utilities Authority (FPUA) has no immediate plans to bring it on-line.

The 37.5 MW and the 56.1 MW steam generators are regulated under the federal Acid Rain program.

Unregulated emissions units and/or activities at the facility are 2.75 MW West Diesel No. 1 (EU 001), 2.75 MW West Diesel No. 2 (EU 002), Cooling Tower (EU 009), and General Purpose Internal Combustion Engines (EU 010).

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Proc. Fee
003	23.4 MW Combined-Cycle Gas Turbine Unit #9		
007	37.5 MW Boiler Unit #7		
008	56.1 MW Boiler Unit #8		
004	16.5 MW Boiler Unit #6		

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 Email Address:	
5. Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the facility 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 requirements identified in this application to which the facility 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.* Signature Date	

APPLICATION INFORMATION

Application Responsible Official Certification

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

1. Application Responsible Official Name:
Thomas W. Richards, P.E., Director of Electric System

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.

3. Application Responsible Official Mailing Address...
Organization/Firm: **Ft. Pierce Utilities Authority**
Street Address: **P.O. Box 3191**
City: **Ft. Pierce** State: **FL** Zip Code: **34948**

4. Application Responsible Official Telephone Numbers...
Telephone: **(772) 466-1600** ext.**3400** Fax: **(772)595-9841**

5. Application Responsible Official Email Address:

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

Signature　　　　　　　　　　　　Date 6/21/07

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Kennard F. Kosky**
   Registration Number: **14996**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc. ****
   Street Address: **6241 NW 23rd Street, Suite 500**
   City: **Gainesville** State: **FL** Zip Code: **32653**
3. Professional Engineer Telephone Numbers...
   Telephone: **(352) 336-5600** ext.**516** Fax: **(352) 336-6603**
4. Professional Engineer Email Address: **kkosky@golder.com**
5. Professional Engineer Statement:

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

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

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

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

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

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

Kennard F. Kosky 6/21/07

Signature Date

(seal) KENNARD F. KOSKY LICENSE No. 14996 STATE OF FLORIDA PROFESSIONAL ENGINEER

* Attach any exception to certification statement.
**Board of Professional Engineers Certificate of Authorization # 00001670

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **566.8** North (km) **3,036.3**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **27/27/00** Longitude (DD/MM/SS) **80/19/26**	
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 : **Emission units designated in this application correspond to those in FDEP Permit No. 1110003-005-AV. EU004 (16.5 MW Boiler Unit No. 6) is in an extended shut down situation.**			

Facility Contact

1. Facility Contact Name: **John Tompeck, Planning Engineer**
2. Facility Contact Mailing Address... Organization/Firm: **Ft. Pierce Utilities Authority** Street Address: **311 North Indian River Drive** City: **Ft. Pierce** State: **FL** Zip Code: **34950**
3. Facility Contact Telephone Numbers: Telephone: **(772) 466-1600** ext. **5201** Fax: **(772) 465-7596**
4. Facility Contact Email Address: **jtompeck@fpua.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 Email Address:

FACILITY INFORMATION

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: **Combined-cycle Gas Turbine Unit No. 9 (EU 003) is subject to NSPS Subpart GG, Standards of Performance for Stationary Gas Turbines.** **56.1 MW Boiler Unit No. 8 (EU 008) is subject to NSPS Subpart D, Standards of Performance for Fossil Fuel-fired Steam Generators (construction after 8/17/71).**	

FACILITY INFORMATION

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
PM	A	N
PM_{10}	A	N
CO	A	N
VOC	A	N
SO_2	A	N
NO_x	A	N

FACILITY INFORMATION

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 No.s Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

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

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☒ Attached, Document ID: **FPU-FI-C1** ☐ Previously Submitted, Date:____
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: **See EU Sections** ☐ Previously Submitted, Date:____
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: **FPU-FI-C3** ☐ Previously Submitted, Date:____

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:____
3.	Rule Applicability Analysis: ☐ Attached, Document ID:____
4.	List of Exempt Emissions Units (Rule 62-210.300(3), F.A.C.): ☐ 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

FACILITY INFORMATION

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units (Rule 62-210.300(3)(a) or (b)1., F.A.C.): ☐ Attached, Document ID:_____ ☐ Not Applicable (no exempt units at facility)	

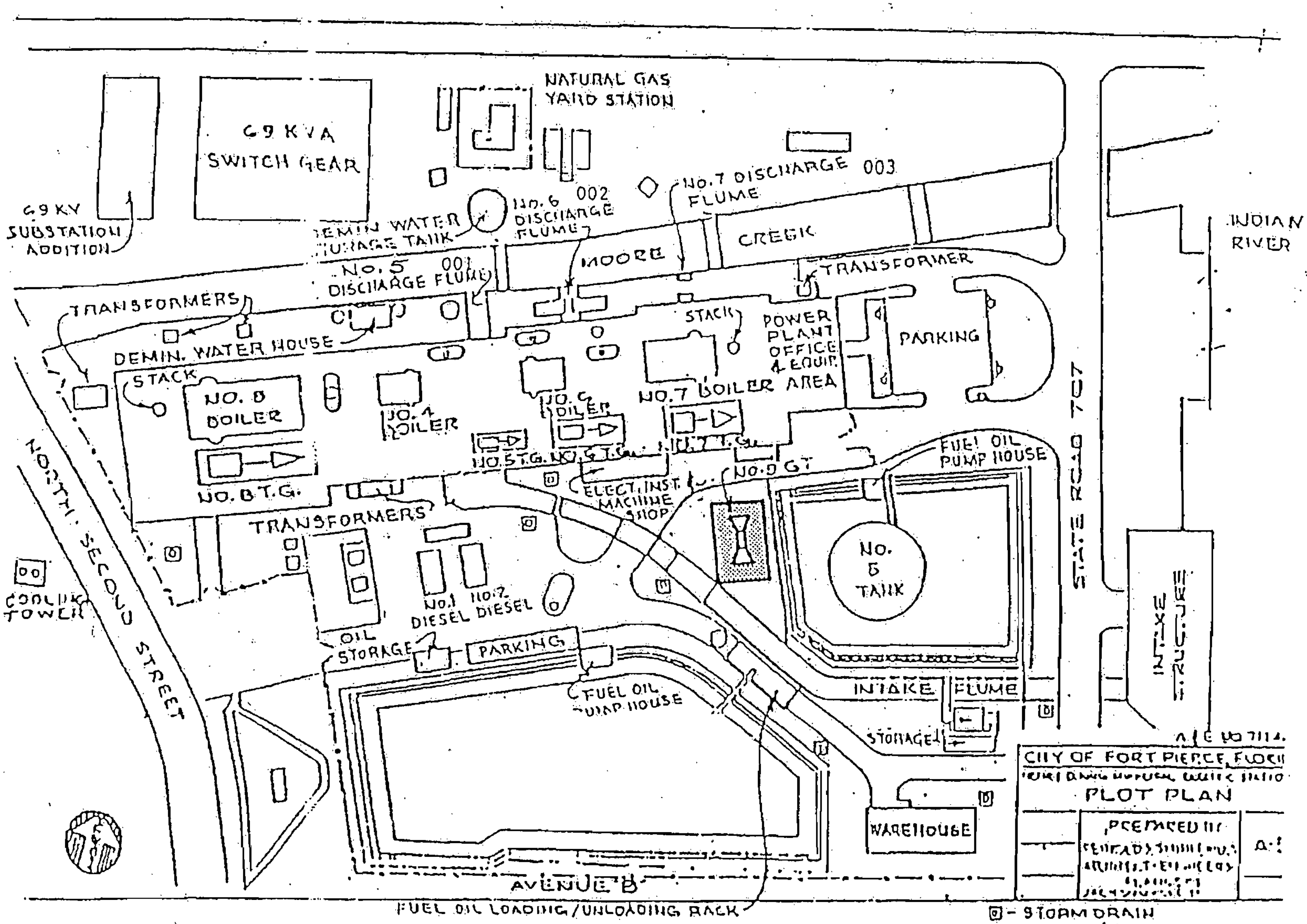
Additional Requirements for Title V Air Operation Permit Applications

1.	List of Insignificant Activities (Required for initial/renewal applications only): ☒ Attached, Document ID: **FPU-FI-CV1** ☐ 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: **FPU-FI-CV2** ☐ 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: **FPU-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: **FPU-FI-CV4** ☐ Equipment/Activities On site 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:**FPU-FI-CV6** ☒ Not Applicable

Additional Requirements Comment

ATTACHMENT FPU-FI-C1

FACILITY PLOT PLAN



Attachment FPU-FI-C1
Site Plan
07387523/App/TV0507/FPU-FI-C1

Source: Golder, 2006.

REV.	SCALE:	
DESIGN		
CADD		
CHECK		
REVIEW		

Golder Associates

ATTACHMENT FPU-FI-C3

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

ATTACHMENT FPU-FI-C3

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

The facility has negligible amounts of unconfined particulate matter as a result of the operation of the facility. The only potential source of unconfined particulate emissions is vehicle traffic.

Operational measures are undertaken at the facility which also minimize particulate emissions, in accordance with 62-296.320(4)(c)2, F.A.C.:

- Maintenance of paved roads and parking areas,
- Regular mowing of grass and care of vegetation, and
- Limiting access to plant property by unnecessary vehicles.

ATTACHMENT FPU-FI-CV1

LIST OF INSIGNIFICANT ACTIVITIES

ATTACHMENT FPU-FI-CV1
LIST OF INSIGNIFICANT ACTIVITIES

A list of existing units and/or activities that are considered to be insignificant and are exempted from Title V permitting under Rule 62-213.430(6) is presented below. The exempt activities listed are also those activities that are included in Rule 62-210.300(3)(a) which would not exceed the thresholds in Rule 62-213.430(6)(b)3.

Brief Description of Emissions Units and/or Activities:

- No. 2 Fuel Oil Storage Tank No. 5 – 922,901 gallons.
- Waste Oil Storage Tank.
- Compressed nitrogen bottles.
- Storage & use of water treatment chemicals.
- 55 gallon drum of Trichloroethylene and Perchloroethylene.
- Lube Oil Storage Area.
- Parts Washer (aliphatic hydrocarbon solvent).
- Miscellaneous painting activities.
- Miscellaneous welding activities.
- Oil/Water Separator.

ATTACHMENT FPU-FI-CV2

IDENTIFICATION OF APPLICABLE REQUIREMENTS

ATTACHMENT FPU-FI-CV2
TITLE V CORE LIST

Effective: 03/01/02
(Updated based on current version of FDEP Air Rules)

[**Note:** The Title V Core List is meant to simplify the completion of the "List of Applicable Regulations" for DEP Form No. 62-210.900(1), Application for Air Permit - Long Form. The Title V Core List is a list of rules to which all Title V Sources are presumptively subject. The Title V Core List may be referenced in its entirety, or with specific exceptions. The Department may periodically update the Title V Core List.]

Federal: ***(description)***

40 CFR 61, Subpart M: NESHAP for Asbestos.

40 CFR 82: Protection of Stratospheric Ozone.
40 CFR 82, Subpart B: Servicing of Motor Vehicle Air Conditioners (MVAC).
40 CFR 82, Subpart F: Recycling and Emissions Reduction.

State: ***(description)***

CHAPTER 62-4, F.A.C.: PERMITS, effective 02-07-06

62-4.030, F.A.C.: General Prohibition.
62-4.040, F.A.C.: Exemptions.
62-4.050, F.A.C.: Procedure to Obtain Permits; Application.
62-4.060, F.A.C.: Consultation.
62-4.070, F.A.C.: Standards for Issuing or Denying Permits; Issuance; Denial.
62-4.080, F.A.C.: Modification of Permit Conditions.
62-4.090, F.A.C.: Renewals.
62-4.100, F.A.C.: Suspension and Revocation.
62-4.110, F.A.C.: Financial Responsibility.
62-4.120, F.A.C.: Transfer of Permits.
62-4.130, F.A.C.: Plant Operation - Problems.
62-4.150, F.A.C.: Review.
62-4.160, F.A.C.: Permit Conditions.
62-4.210, F.A.C.: Construction Permits.
62-4.220, F.A.C.: Operation Permit for New Sources.

CHAPTER 62-210, F.A.C.: STATIONARY SOURCES - GENERAL REQUIREMENTS, effective 05-09-07

62-210.300, F.A.C.: Permits Required.
62-210.300(1), F.A.C.: Air Construction Permits.
62-210.300(2), F.A.C.: Air Operation Permits.
62-210.300(3), F.A.C.: Exemptions.
62-210.300(5), F.A.C.: Notification of Startup.
62-210.300(6), F.A.C.: Emissions Unit Reclassification.
62-210.300(7), F.A.C.: Transfer of Air Permits.

62-210.350, F.A.C.: Public Notice and Comment.
62-210.350(1), F.A.C.: Public Notice of Proposed Agency Action.
62-210.350(2), F.A.C.: Additional Public Notice Requirements for Emissions Units Subject to Prevention of Significant Deterioration or Nonattainment-Area Preconstruction Review.
62-210.350(3), F.A.C.: Additional Public Notice Requirements for Sources Subject to Operation Permits for Title V Sources.

62-210.360, F.A.C.: Administrative Permit Corrections.
62-210.370(3), F.A.C.: Annual Operating Report for Air Pollutant Emitting Facility.
62-210.400, F.A.C.: Emission Estimates.
62-210.650, F.A.C.: Circumvention.
62-210.700, F.A.C.: Excess Emissions.

62-210.900, F.A.C.: Forms and Instructions.
62-210.900(1), F.A.C.: Application for Air Permit – Title V Source, Form and Instructions.
62-210.900(5), F.A.C.: Annual Operating Report for Air Pollutant Emitting Facility, Form and Instructions.
62-210.900(7), F.A.C.: Application for Transfer of Air Permit – Title V and Non-Title V Source.

CHAPTER 62-212, F.A.C.: STATIONARY SOURCES - PRECONSTRUCTION REVIEW, effective 02-02-06

CHAPTER 62-213, F.A.C.: OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION, effective 04-14-03

62-213.205, F.A.C.: Annual Emissions Fee.
62-213.400, F.A.C.: Permits and Permit Revisions Required.
62-213.410, F.A.C.: Changes Without Permit Revision.
62-213.412, F.A.C.: Immediate Implementation Pending Revision Process.
62-213.415, F.A.C.: Trading of Emissions Within a Source.
62-213.420, F.A.C.: Permit Applications.
62-213.430, F.A.C.: Permit Issuance, Renewal, and Revision.
62-213.440, F.A.C.: Permit Content.
62-213.450, F.A.C.: Permit Review by EPA and Affected States
62-213.460, F.A.C.: Permit Shield.

62-213.900, F.A.C.: Forms and Instructions.
62-213.900(1), F.A.C.: Major Air Pollution Source Annual Emissions Fee Form.
62-213.900(7), F.A.C.: Statement of Compliance Form.

ATTACHMENT FPU-FI-CV2
TITLE V CORE LIST

Effective: 03/01/02
(Updated based on current version of FDEP Air Rules)

CHAPTER 62-296, F.A.C.: STATIONARY SOURCES - EMISSION STANDARDS, effective 05-09-07

62-296.320(4)(c), F.A.C.: Unconfined Emissions of Particulate Matter.

62-296.320(2), F.A.C.: Objectionable Odor Prohibited.

CHAPTER 62-297, F.A.C.: STATIONARY SOURCES - EMISSIONS MONITORING, effective 2-12-04

62-297.310, F.A.C.: General Test Requirements.
62-297.310(4), F.A.C.: Applicable Test Procedures.
62-297.310(5), F.A.C.: Determination of Process Variables.
62-297.310(6), F.A.C.: Repaired Stack Sampling Facilities.
62-297.310(7), F.A.C.: Frequency of Compliance Tests.
62-297.510(8), F.A.C.: Test Report.
62-297.620, F.A.C.: Exceptions and Approval of Alternate Procedures and Requirements.

Miscellaneous:

CHAPTER 28-106, F.A.C.: Decisions Determining Substantial Interests
CHAPTER 62-110, F.A.C.: Exception to the Uniform Rules of Procedure, effective 07-01-98
CHAPTER 62-256, F.A.C.: Open Burning and Frost Protection Fires, effective 11-30-94
CHAPTER 62-257, F.A.C.: Asbestos Notification and Fee, effective 02-09-99
CHAPTER 62-281, F.A.C.: Motor Vehicle Air Conditioning Refrigerant Recovery and Recycling, effective 09-10-96

ATTACHMENT FPU-FI-CV3

COMPLIANCE REPORT AND PLAN

Department of
Environmental Protection

Division of Air Resource Management

STATEMENT OF COMPLIANCE - TITLE V SOURCE

REASON FOR SUBMISSION (Check one to indicate why this statement of compliance is being submitted)

☒ **Annual Requirement**	☐ **Transfer of Permit**	☐ **Permanent Facility Shutdown**

REPORTING PERIOD*	REPORT DEADLINE**
January through December of 2006 (year)	March 1, 2007

*The statement of compliance must cover all conditions that were in effect during the indicated reporting period, including any conditions that were added, deleted, or changed through permit revision.
**See Rule 62-213.440(3)(a)2., F.A.C.

Facility Owner/Company Name: Fort Pierce Utilities Authority

Site Name: H. D. King Power Plant Facility ID No. 1110003 County: St. Lucie

COMPLIANCE STATEMENT (Check only one of the following three options)

X A. This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part, and there were no reportable incidents of deviations from applicable requirements associated with any malfunction or breakdown of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above.

____ B. This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part; however, there were one or more reportable incidents of deviations from applicable requirements associated with malfunctions or breakdowns of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above, which were reported to the Department. For each incident of deviation, the following information is included:

1. Date of report previously submitted identifying the incident of deviation.
2. Description of the incident.

____ C. This facility was in compliance with all terms and conditions of the Title V Air Operation Permit and, if applicable, the Acid Rain Part, EXCEPT those identified in the pages attached to this report and any reportable incidents of deviations from applicable requirements associated with malfunctions or breakdowns of process, fuel burning or emission control equipment, or monitoring systems during the reporting period identified above, which were reported to the Department. For each item of noncompliance, the following information is included:

1. Emissions unit identification number.
2. Specific permit condition number (note whether the permit condition has been added, deleted, or changed during certification period).
3. Description of the requirement of the permit condition.
4. Basis for the determination of noncompliance (for monitored parameters, indicate whether monitoring was continuous, i.e., recorded at least every 15 minutes, or intermittent).
5. Beginning and ending dates of periods of noncompliance.
6. Identification of the probable cause of noncompliance and description of corrective action or preventative measures implemented.
7. Dates of any reports previously submitted identifying this incident of noncompliance.

For each incident of deviation, as described in paragraph B. above, the following information is included:

1. Date of report previously submitted identifying the incident of deviation.
2. Description of the incident.

STATEMENT OF COMPLIANCE - TITLE V SOURCE

RESPONSIBLE OFFICIAL CERTIFICATION

I, the undersigned, am a responsible official (Title V air permit application or responsible official notification form on file with the Department) of the Title V source for which this document is being submitted. With respect to all matters other than Acid Rain program requirements, I hereby certify, based on the information and belief formed after reasonable inquiry, that the statements made and data contained in this document are true, accurate, and complete.

1/30/07

(Signature of Title V Source Responsible Official) *(Date)*

Name: Thomas W. Richards, P.E. Title: Director, Electric & Gas Systems

DESIGNATED REPRESENTATIVE CERTIFICATION (only applicable to Acid Rain source)

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

1/30/07

(Signature of Acid Rain Source Designated Representative) *(Date)*

Name: Thomas W. Richards, P.E. Title: Director, Electric & Gas Systems

{Note: Attachments, if required, are created by a responsible official or designated representative, as appropriate, and should consist of the information specified and any supporting records. Additional information may also be attached by a responsible official or designated representative when elaboration is required for clarity. This report is to be submitted to both the compliance authority (DEP district or local air program) and the U.S. Environmental Protection Agency(EPA) (U.S. EPA Region 4, Air and EPCRA Enforcement Branch, 61 Forsyth Street, Atlanta GA 30303).}

ATTACHMENT FPU-FI-CV4

LIST OF EQUIPMENT / ACTIVITIES REGULATED – TITLE VI

ATTACHMENT FPU-FI-CV4

LIST OF EQUIPMENT / ACTIVITIES REGULATED — TITLE VI

The H.D. King Power Plant currently has the following equipment that contains more than 50 lbs of charge of any Class I or Class II ozone-depleting substance regulated under Title VI of the CAA:

1. Office Air Conditioner – York 30 tons, contains 180 lbs R22

ATTACHMENT FPU-FI-CV6

REQUESTED ADMINISTRATIVE CHANGES

ATTACHMENT FPU-FI-CV6

REQUESTED ADMINISTRATIVE CHANGES

Fort Pierce Utilities Authority (FPUA) requests administrative changes to reflect the recent revisions to 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines and requests the following changes to the Title V permit:

<u>Condition A.14. (Monitoring of Operations)</u>
FPUA requests that the condition, which currently says:

> *"The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:*
>
> *"(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.*
>
> *"(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with 40 CFR 60.334(b)."*

be revised to add the following:

> *"The owner may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in 60.331(u)."*

<u>Condition A.16. (Test Methods and Procedures)</u>
FPUA requests the regulation cited in the condition to be revised from 40 CFR 60.335(a) to 40 CFR 60.334(b)(9).

<u>Condition A.17. (Test Methods and Procedures)</u>
FPUA requests the regulation cited in the condition to be revised from 40 CFR 60.335(c)(1) to 40 CFR 60.334(b)(1).

<u>Condition A.18. (Test Methods and Procedures)</u>
FPUA requests the regulation cited in the condition to be revised from 40 CFR 60.335(c)(2) to 40 CFR 60.335(b)(4). The condition, which currently says:

> *"When determining compliance with 40 CFR 60.332, Subpart GG – Standards of Performance for Stationary Gas Turbines, the*

monitoring device of 60.334(a) shall be used to determine the fuel consumption and the water –to-fuel ratio necessary to comply with the permitted NO_x standard at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer."

Should be revised to:

"When determining compliance with the applicable 60.332 NOx emission limit, the monitoring device of 60.334(a) shall be used to determine the fuel consumption and the water to fuel ratio."

Condition A.19. (Test Methods and Procedures)
FPUA requests the condition, which currently says:

"The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 as follows:

"c. U.S. EPA Method 20 (40 CFR 60, Appendix A) shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxides and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in 40 CFR 60.335(c)(2)."

Be revised to:

"The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in 60.332. by conducting performance tests using EPA Method 20, ASTM D6522-00 (incorporated by reference, 60.17), or EPA Method 7E."

The regulation cited in the condition should be revised from 40 CFR 60.335(c)(3) to 40 CFR 60.335(b)(4).

Condition A.21. (Test Methods and Procedures)
FPUA requests that the condition, which currently says:

"The fuel sulfur content of 0.5 percent, by weight, shall be evaluated using ASTM D1552, ASTM D1072, ASTM D3031, ASTM D4084, or ASTM D3246, or latest edition."

Be revised to:

"The fuel sulfur content of 0.5 percent, by weight, shall be evaluated using ASTM D129-00, D2622-98, D4294-02, D1266-98, D5453-00 or D1552-01 (incorporated by reference, 60.17."

Condition A.22. (Test Methods and Procedures)
FPUA requests the condition, which currently says:

> *"To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in 40 CFR 60.335(a) and 40 CFR 60.335(d) of 40 CFR 60.335 to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.""*

Should be revised to:

> *"To meet the requirements of 40 CFR 60.334(h), the owner or operator shall use the methods specified in 40 CFR 60.335(b)(9) and 60.335(b)(10) to determine the nitrogen and sulfur content of the fuel being fired. The analysis may be performed by the owner or operator, a service contractor retained by the the owner or operator, the fuel vendor, or any other qualified agency."*

Condition D.39. (Record Keeping and Reporting Requirements)
FPUA requests the regulation cited in the condition to be revised from 40 CFR 60.334(c)(1) to 40 CFR 60.334(J)(1).

No other changes are requested or necessary.

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 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 for air permit. 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 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/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. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** 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 construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:

   Combined Cycle Gas Turbine Unit #9

3. Emissions Unit Identification Number: **003**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A		**1/1/89**	**49**	☐ Yes ☒ No

9. Package Unit:
   Manufacturer: **GE** Model Number: **295352**

10. Generator Nameplate Rating: **32** MW

11. Emissions Unit Comment:

    Emission unit is a 23.4-MW natural gas or No. 2 fuel oil-fired combined-cycle gas turbine with a heat recovery steam generator (HRSG). The HRSG is not supplementary-fired. The HRSG steam output supplies an 8.2 MW turbine generator. Emission unit began commercial operation in May 1990.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Steam Injection for NO_x control.**	
2. Control Device or Method Code(s): **28**	

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: **415.0** 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 based on lower heating value (LHV) of natural gas or No. 2 fuel oil.** **Natural gas is used as primary fuel with No. 2 fuel oil used as backup.**	

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: **No. 9 GT**	2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking:

Emission unit can exhaust through either a by-pass stack (simple-cycle mode) or heat recovery steam generator (HRSG) stack (combined-cycle mode).

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:
008

5. Discharge Type Code: **V**	6. Stack Height: **68** feet	7. Exit Diameter: **11.2** feet
8. Exit Temperature: **426** °F	9. Actual Volumetric Flow Rate: **353,500** acfm	10. Water Vapor: **9.07** %

11. Maximum Dry Standard Flow Rate: **191,556** dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **566.8** North (km): **3,036.3**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) **27/27/00** Longitude (DD/MM/SS) **80/19/26**

15. Emission Point Comment:
Exit temperature and exhaust flow rates are from Title V renewal application dated July 2002.

Diameter is the equivalent of a rectangular stack of 10.6' x 9.25'.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type): **Internal Combustion Engines; Electric Generation; Natural Gas; Turbine**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million cubic feet natural gas burned**	
4. Maximum Hourly Rate: **0.437**	5. Maximum Annual Rate: **3,827**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment: **Based on natural gas lower heating value (LHV) of 950 Btu/ft^3.** **Maximum hourly rate = 415 MMBtu/hr /950 MMBtu/MM ft^3 (LHV) = 0.437 MM ft^3/hr** **Maximum annual rate = 415 MMBtu/hr /950 MMBtu/MM ft^3 x 8,760 hr/yr = 3,826.7 MM ft^3/yr.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type): **Internal Combustion Engines; Electric Generation; Distillate Oil (Diesel); Turbine**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **1,000 Gallons burned**	
4. Maximum Hourly Rate: **3.192**	5. Maximum Annual Rate: **27,965**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **130**
10. Segment Comment: **Based on No. 2 oil lower heating value (LHV) of 130 MMBtu/thousand gallons.** **Maximum hourly rate = 415 MMBtu/hr /130 MMBtu/1,000 gallon = 3,192.3 gallons/hr.** **Maximum annual rate = 3,192.3 gallons/hr x 8,760 hr/yr = 27,964.6x10^3 gallons/yr.** **No. 2 fuel oil is used as a backup fuel only.**		

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
PM			NS
PM_{10}			NS
CO			EL
VOC			NS
SO_2			EL
NO_x	028		EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **32.85** lb/hour **110.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **32.85 lb/hr** Reference: **Permit No. 1110003-005-AV/AC 56-141460**	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: **Annual emissions = 32.85 lb/hr x 8,760 hrs/yr x ton/2,000 lbs = 110.4 TPY.**	
11. Potential Fugitive and Actual Emissions Comment:	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **32.85 lb/hr**	4. Equivalent Allowable Emissions: **32.85** lb/hour **110.4** tons/year
5. Method of Compliance: **Annual compliance test using EPA Method 10.**	
6. Allowable Emissions Comment (Description of Operating Method): **Permit No. 1110003-005-AV/AC56-141460.**	

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/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **319** lb/hour **1,397.2** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **150 ppmvd @ 15% O_2** Reference: **40 CFR 60.333 (a), Subpart GG**	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:
Hourly emissions = 150 ft^3/1,000,000 ft^3 x 8,710 ft^3/MMBtu x 415 MMBtu/hr x 64 lb/385.3 ft^3 x (20.9/(20.9-15)) = 319.03 lb/hr
Annual emissions = 319.0 lb/hr x 8,760 hrs/yr x ton/2,000 lb = 1,397.2 TPY

11. Potential Fugitive and Actual Emissions Comment:
Hourly emissions based on permit limit of 0.015 percent SO_2 by volume at 15 percent O_2 on a dry basis based on 40 CFR 60, Subpart GG.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **150 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **319.0** lb/hour **1,397.2** tons/year
5. Method of Compliance: **Annual compliance test using EPA Method 20.**	
6. Allowable Emissions Comment (Description of Operating Method): **40 CFR 60 Subpart GG (40 CFR 60.333(a)).**	

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: **0.5% Sulfur**	4. Equivalent Allowable Emissions: **226.7** lb/hour **992.7** tons/year
5. Method of Compliance: **Fuel Analysis**	
6. Allowable Emissions Comment (Description of Operating Method): **Maximum sulfur content of No. 2 fuel oil limited to 0.5 percent by weight. No. 2 oil used as backup fuel only.** **Equivalent allowable emissions = 3,192.3 gal/hr x 7.1 lb/gal x 0.5/100 x 64/32 = 226.7**	

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/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

<u>Potential/Estimated Fugitive Emissions</u>

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **128.4** lb/hour **562.4** tons/year	4. Synthetically Limited? ☐ Yes ☒ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **84 ppmvd @15% O_2** Reference: **40 CFR 60.332 (a)(1), Subpart GG**	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:

Hourly emissions = 84 ft^3/1,000,000 ft^3 x 8,710 ft^3/MMBtu x 415 MMBtu/hr x 46 lb/385.3 ft^3 x [(20.9/(20.9-15)] = 128.4 lb/hr
Annual emissions = 128.4 lb/hr x 8,760 hr/yr x ton/2,000 lb = 562.4 TPY

11. Potential Fugitive and Actual Emissions Comment:

Hourly emissions based on permit limit of 84 ppmv at 15% O_2 on a dry basis.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **84 ppmvd @15% O_2**	4. Equivalent Allowable Emissions: **128.4** lb/hour **562.4** tons/year
5. Method of Compliance: **Annual compliance test using EPA Method 20. Continuous monitoring of fuel consumption and steam-to-fuel ratio.**	
6. Allowable Emissions Comment (Description of Operating Method): **40 CFR 60.332(a)(1), Subpart GG Permit No. 1050003-013-AV / AC 56-141460.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: VE15	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: 15 % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: Annual VE test using EPA Method 9	
5. Visible Emissions Comment: Permit No. 1110003-005-AV/AC 56-141460.	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

EMISSIONS UNIT INFORMATION
Section [1]
Combined Cycle Gas Turbine Unit #9

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: WTF	2. Pollutant(s):
3. CMS Requirement:	☒ Rule Other
4. Monitor Information... Manufacturer: GE Model Number: Speedtronic Mark IV	Serial Number:
5. Installation Date: 1/2/1988	6. Performance Specification Test Date: 11/9/1989
7. Continuous Monitor Comment: Monitoring of steam to fuel ratio. 40 CFR 60.334 Permit No. 1110003-005-AV	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: FLOW	2. Pollutant(s):
3. CMS Requirement:	☒ Rule Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment: Monitoring of fuel flow. 40 CFR 60.334 Permit No. 1110003-005-AV	

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: FPU-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: FPU-EU1-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: FPU-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: FPU-EU1-I4 ☐ Previously Submitted, Date ____
   ☐ 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: August 24, 2006

   ☐ To be Submitted, Date (if known): ____
   Test Date(s)/Pollutant(s) Tested: ____

   ☐ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: ____ ☒ Not Applicable

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 (Rule 62-212.400(4)(d), F.A.C., and Rule 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	

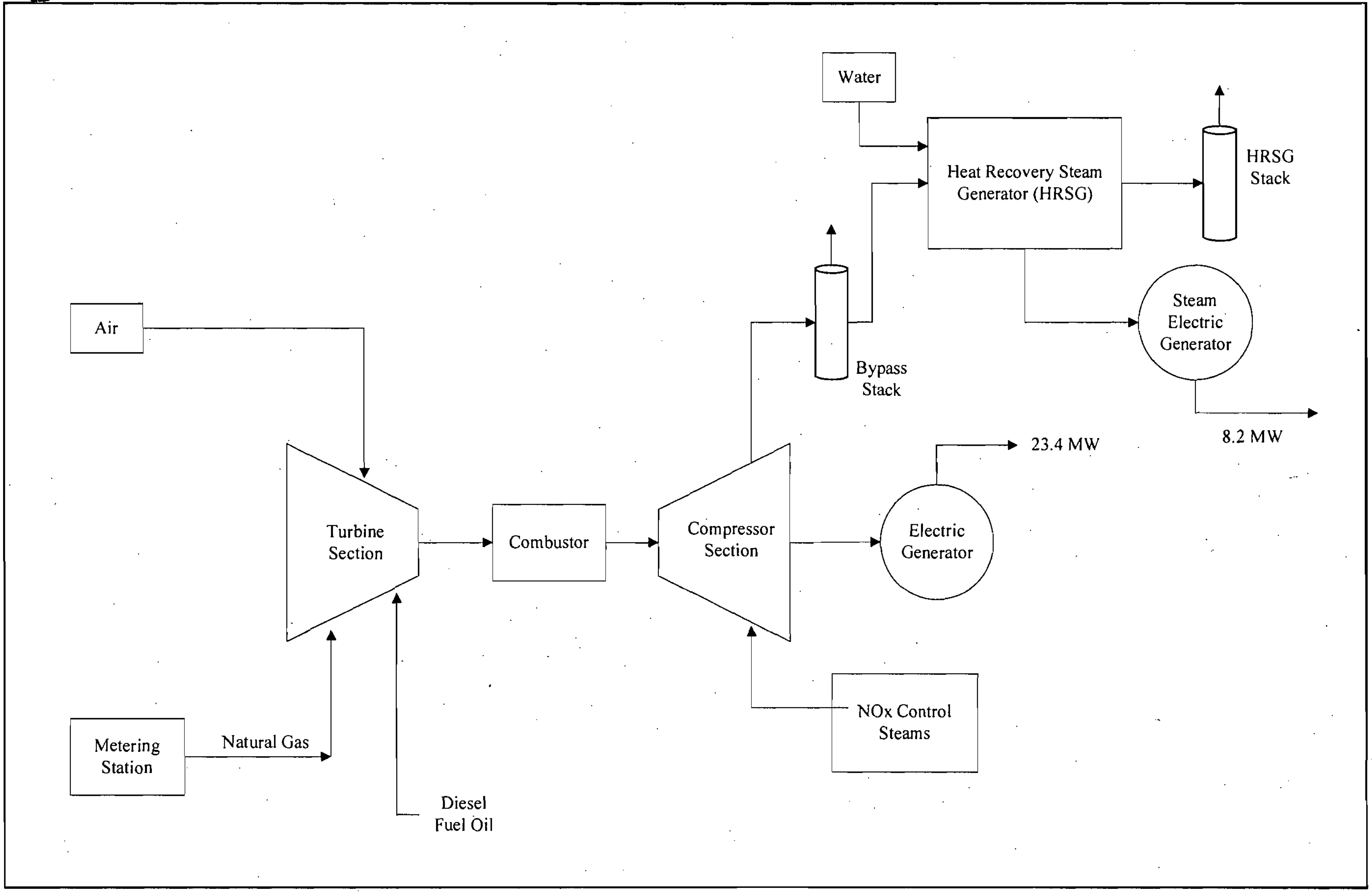
Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☒ Attached, Document ID: FPU-EU1-IV1 ☐ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _____ ☒ Not Applicable	
3. Alternative Methods of Operation ☒ Attached, Document ID: FPU-EU1-IV3 ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☒ Not Applicable	

Additional Requirements Comment

ATTACHMENT FPU-EU1-I1

PROCESS FLOW DIAGRAM



Attachment FPU-EU1-I1
23.4 MW Combined-Cycle Gas Turbine Unit #9
Process Flow Diagram
Fort Pierce Utilities - H.D. King Power Plant
Fort Pierce, Florida

Process Flow Legend
Solid/Liquid
Gas
Steam

Filename: 07387523/PROCESS FLOW DIAGRAMS.VSD
Date: 06/18/07

Golder Associates

ATTACHMENT FPU-EU1-I2

FUEL ANALYSIS OR SPECIFICATION

Florida Gas Transmission
Spot Analysis of Natural Gas
Brooker Station

Date: August 23, 2006
Time: 10:38 AM

Component Name	Mole %
Hexane	.068
Propane	.448
Isobutene	.106
n-Butane	.098
Isopentane	.039
n-Pentane	.024
Nitrogen	.535
Methane	95.141
CO_2	.991
Ethane	2.549
Totals	100.00

BTU/scf-1035 Total Sulfur-.054 ppm Total Sulfur-.003 grams/hcf

BSI INSPECTORATE

CERTIFICATE OF ANALYSIS

JOB NO.	TA13161
LAB NO.	L050720168

VESSEL	SUBMITTED ANALYSIS	REPORT DATE	08/15/05
PRODUCT	#2 FUEL OIL		
TERMINAL/PORT	H.D. KING POWER PLANT		
SAMPLE FROM	SHORE TANK 5	DATE SAMPLED	7/20/05
SAMPLE SUBMITTED BY	FORT PIERCE UTILITIES		
ANALYSIS PERFORMED BY	BSI INSPECTORATE AMERICA CORP. - TAMPA, FL		
CLIENT(S) REF.	N/A		

TEST	METHOD	RESULTS
API GRAVITY @ 60 °F	D 287	34.6
DENSITY @ 15 °C	D 287	0.8514
SULFUR, WT. %	D 4294	0.0364
HEAT OF COMBUSTION, BTU's/LB	D 240	19,494
HEAT OF COMBUSTION, BTU's/GAL	D 240	138,322
NITROGEN, PPM	D 5228	151
SODIUM, PPM	AAS	< 1.0
VANADIUM, PPM	AAS	< 1.0
LEAD, PPM	AAS	< 1.0

Q-ANAL
REV #3 -

Ted Gabric

BSI INSPECTORATE AMERICA

ATTACHMENT FPU-EU1-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

STEAM INJECTION

GENERAL

The steam injection control system provides the necessary flow of steam to the gas turbine combustion system in order to meet Federal and State regulations regarding the emission of nitrogen oxides (NO_x). The regulations not only require meeting the emission levels, but also require the continuous monitoring of fuel flow, steam injection flow, and other machine parameters to verify that the regulations are being met.

STEAM INJECTION HARDWARE

The steam injection control system hardware is located off-base, mounted in the steam piping. Figure SIR4000-1 shows a schematic of these control devices.

Devices

1. A metering tube and orifice are the primary devices for measurement of steam flow.

2. Two differential transmitters (96SJ-1, -2) measure pressure drop across the orifice. The two transmitters operate in a split-range mode, where one transmitter is calibrated to monitor the lower range of flow and the other, the higher range. Thus, the total flow range measurement accuracy is improved compared to a single transmitter arrangement.

3. A pressure transmitter (96PJ-1) measures steam pressure for calculation of steam flow and indication of steam condition.

4. Three thermocouples (ST-SJ-1, -2, -3) measure steam temperature for calculation of steam flow and indication of steam condition.

5. A pneumatically operated stop valve (controlled by trip solenoid 20SJ-1) opens to permit steam injection flow and closes to shut off flow when the system is not operating or when the system is tripped. A limit switch (33SJ-1) indicates valve-closed position.

6. Two pneumatically operated valves (controlled by solenoid valves 20BS-1, -2) provide steam-line condensate drain and warm-up prior to injection. Limit switches indicate valve position.

7. A steam control valve regulates the flow of steam to the gas turbine. This valve is driven by an electromechanical motor actuator which receives direction (open or close) and run signals from the gas turbine control system. The control valve has a limit switch which indicates valve fully closed position.

CONTROL PANEL/OPERATOR INTERFACES

The turbine control panel provides the necessary information to the operator to indicate the operational status of the steam injection system. The steam injection system is manually enabled by selecting the "Manual Control Display" on the turbine control panel CRT, finding the "Steam Injection Control" page and pressing the "Steam Inj On" softswitch. The steam injection system is disabled by pressing the "Steam Inj Off" softswitch. When the steam

- Assuming the turbine shutdown sequence continues, when the generator breaker opens, the steam stop valve will close and the #1 drain valve will open.

- The operator should now close the steam-line isolation valve.

STEAM FLOW CONTROL

The steam flow program determines a steam injection flow setpoint based on fuel flow rate, ambient temperature and sometimes specific humidity. Figure SIR4000-2 shows a typical schedule. Note that there is a CONTROL schedule and a COMPLIANCE schedule. The COMPLIANCE schedule represents the amount of steam required to just meet the NO_x emissions requirement. If steam flow should ever fall to or below this schedule, an alarm will occur. The CONTROL schedule is the one used to control steam flow to the turbine. It is set higher than the COMPLIANCE schedule to account for the control system dead-band and normal operational transients. The separation between the curves is set by constant WQKR3.

As shown in Figure SIR4000-2, steam flow is initiated when fuel flow to the turbine reaches the value specified by constant WQK( )E. At this point, the steam injection flow setpoint is released from 0. The setpoint assumes a value in accordance with the measured fuel flow, ambient temperature, and specific humidity. The control valve is allowed to ramp open until steam flow equals the setpoint. The ramp consists of a series of small steps. The control valve motor is turned on (in the open direction) for a fixed length of time and then turned off for another fixed length of time. The on time is set by timer L2WQOFF and the off time by timer L2WQON. The ramp should be adjusted so the control valve opens as quickly as possible without upsetting the steam supply conditions.

Steam flow feedback is calculated from measured pressure drop across a flow orifice, compensated for steam temperature and pressure variations. Where there is a wide flow range, two differential transmitters are supplied to monitor flow in a split-range configuration; one transmitter calibrated for a low flow region, the other calibrated for a high flow region. Automatic switching between the two transmitters is programmed in the control logic of the computer. Based on the selected measurement of differential pressure, steam temperature and steam pressure, steam flow is calculated, forming the feedback for the flow control system.

PROTECTIVE FEATURES

Steam injection system alarm and shutoff conditions are detected by the protection task program within the microcomputer. Certain component or system conditions are alarmed only - to alert the operator of abnormal but not yet critical states. Other conditions result in shutoff of the steam injection system via the control valve or the stop valve.

Steam Supply Condition Trouble

The steam injection protection system monitors steam supply conditions to alarm or shutoff steam flow when abnormal conditions are detected. See Figure SIR4000-3 which illustrates the steam temperature and steam pressure supply conditions that will result in protective actions. Alarm actions are initiated by high or low pressure levels and by high or low temperatures. The low-temperature alarm setpoint is modified with pressure to track the saturation curve. The purpose of this alarm (and subsequent trip) is to insure that the supply steam is superheated. Steam injection shutdown actions are initiated on high steam pressure and high temperature for equipment protection. The steam injection shutdown signal is latched until operator actions are taken. To re-initiate

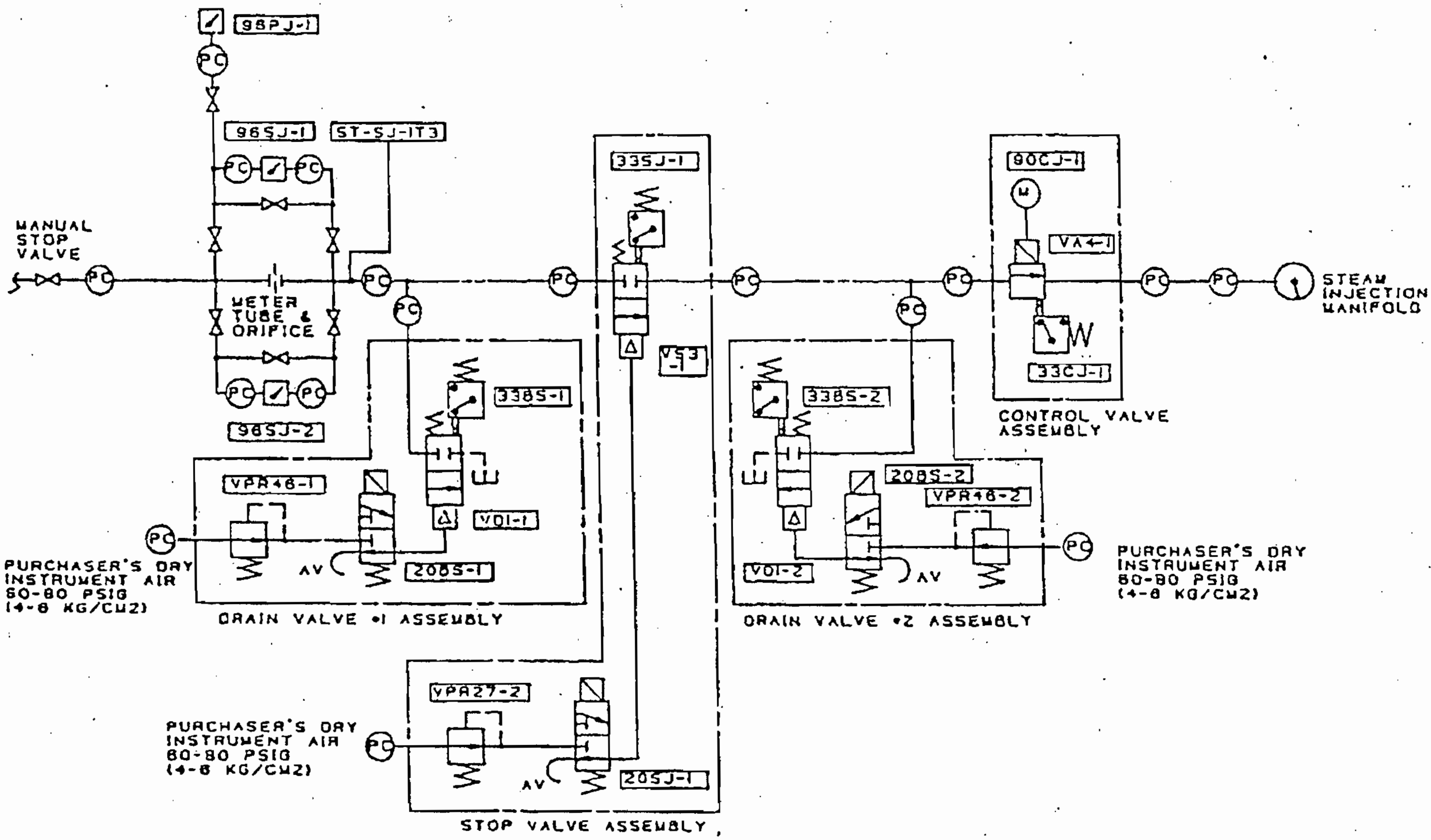


FIGURE SIR4000-1
(788)

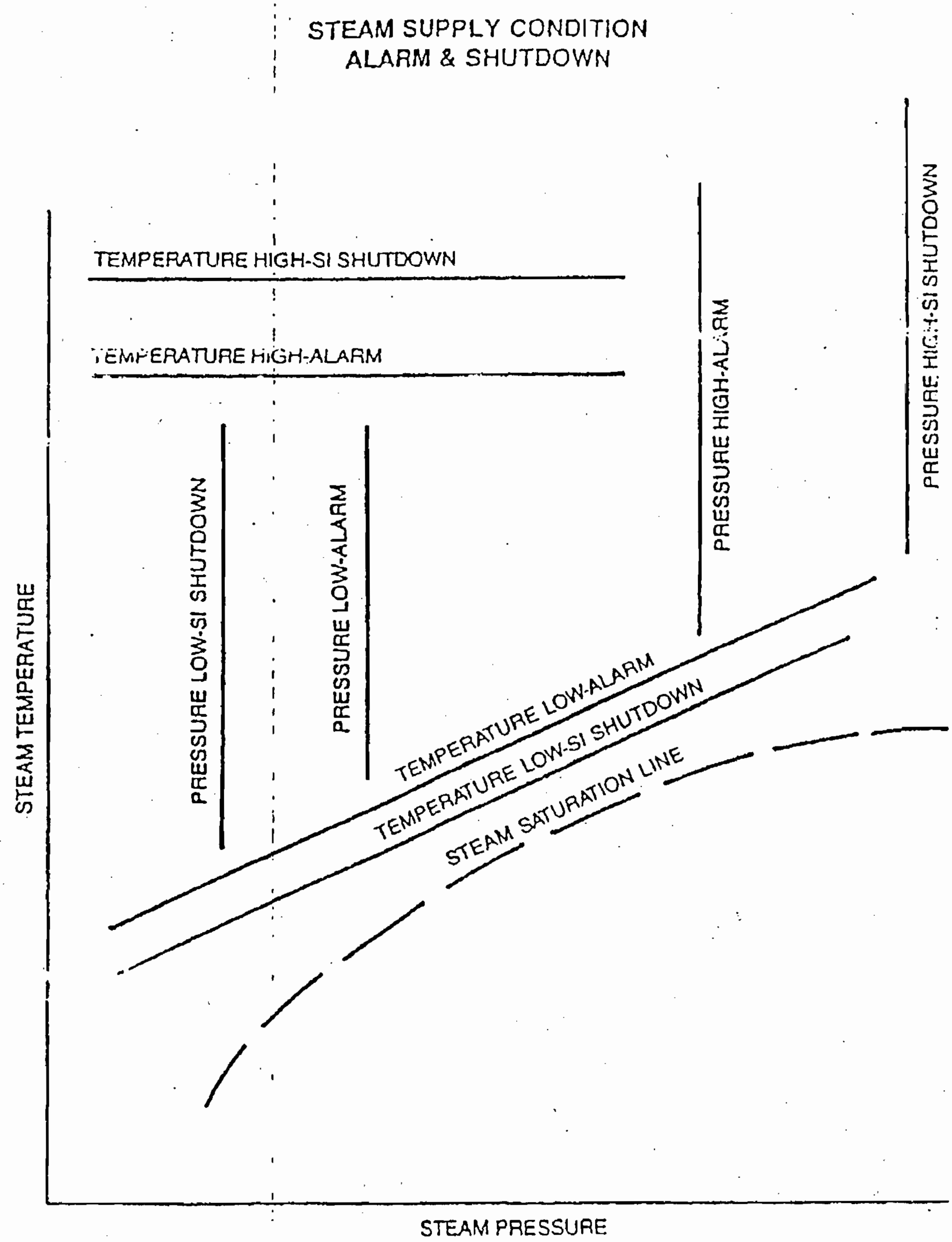


FIGURE SIR4000-3
(788)

GENERAL

The steam injection system provides the necessary flow of steam to the gas turbine combustion system to meet Federal and State exhaust emission requirements by limiting the emission of nitrogen oxides (NO_x) in the turbine exhaust. The strict regulations not only require meeting the emission levels, but also require the continuous monitoring of fuel flow, steam injection flow, and other machine parameters to verify that the regulations are being met.

The steam injection system, shown in the system schematic diagram (see Reference Drawings), consists of steam flow control and regulating valves and control and monitoring devices located off base in the purchaser's steam piping. The steam from this off-base source is supplied in a controlled flow to the turbine's steam injection manifold. The associated automatic electronic control system, part of the turbine control circuits, controlling this steam injection system utilizes the Mark IV computer as the basic control element and is described in the Control and Protection Section.

The main components of the steam injection system include the following:

1. A meter tube and orifice.
2. Differential pressure transmitters, 96SJ-1 and -2.
3. Steam supply pressure transmitter, 96PJ-1.
4. Thermocouple, ST-SJ-1T3.
5. Stop valve, VS3-1, pneumatically operated with limit switch, 33SJ-1.
6. Stop valve-trip solenoid, 20SJ-1.
7. Control air regulator valve, VPR27-2.
8. Steam line drain valves, VD1-1, -2 air actuated with limit switches 33BS-1, -2, -3.
9. Steam line drain valve-solenoid valve, 20BS-1, -2.
10. Drain valve air regulator valve, VPR46-1, -2.
11. Steam injection control valve, VA4-1, with electromechanical actuator and limit switch, 33CJ-1.
12. On-base steam injection manifold and piping to combustion chambers.

FUNCTIONAL DESCRIPTION

For a functional description of the steam injection system, refer to the steam injection system text in the Control and Protection section of this manual.

SYSTEM REQUIREMENTS

STEAM SUPPLY

The purchaser is to supply steam for the steam injection system to meet the system design requirements of flow, temperature and pressure (see Control Specification). The steam supplied must be superheated steam within the design temperature range of the system and must be at the specified minimum pressure to prevent backflow of combustion gases into the steam line. To keep within the system design operating range, the steam should not exceed the maximum specified temperature and pressure, otherwise, damage to seals and valve stem packing could result.

INSTRUMENT AIR

The purchaser is to supply dry instrument air at the pressure range specified on the steam injection piping schematic diagram for operation of the pneumatically operated stop valve and drain valves.

OPERATION

Before operating the steam injection system for the first time following an overhaul or periods of extended shutdown, it is important that the following checks be made:

1. Steam supply is within design parameters.
2. Instrument air supply is at required pressure.
3. Steam line orifice size is correct.
4. Pressure sensing lines are free of liquids.

PRE-OPERATION CHECKS

Prior to operation, check for the following conditions:

1. Panel controls are in Non select positions (Steam Injection OFF).
2. Manual stop valve is open.
3. All hand valves in line of flow are open.
4. All valves to temperature or pressure gauges are open.
5. Steam supply pressure and temperature are in operating range.

START UP

The automatic control system, in conjunction with logic circuits of the microcomputer of the *SPEEDTRONIC* control system, operates the steam injection system control valving and assures that the proper amount of steam injection is provided to the turbine combustion system during operation.

To initiate steam injection the operator must first select the "Manual Control Display" mode at the turbine control panel interface module. This mode will be displayed on the video display scope (CRT). By pressing the NEXT PAGE pushbutton (membrane switch), the display page will change until the "Steam Injection Control" page is reached. Then touching the function switch at the right of the CRT opposite the "Steam Inj ON" display intiates the steam injection control. At this point the automatic steam control circuits take over, initiate the drain and stop valve sequences and control the system. When steam conditions are correct, the steam control valve releases steam into the combustion system at the proper steam-to-fuel flow ratio.

The startup and operating sequence of the steam injection system is described and explained in the Steam Injection control system text of the Control and Protection section of this manual. (See CONTROL AND PROTECTION Tab).

MAINTENANCE

PERIODIC MAINTENANCE

During the first week of operation, the units steam injection on base piping and the control valves in the steam supply line should be checked periodically for leaks or other defects. After initial system checks monthly checks should be made.

All hand-operated valves should be cycled once a month to check freedom of movement. They should be returned to their normal operating position after this.

TROUBLE SHOOTING

The purpose of the system is to provide steam to the turbine combustion system at the desired pressure, temperature and flow. If this does not happen, the following problems may be the cause:

a. Steam supply exhausted.

b. Insufficient supply pressure.

c. Control valve closed.

d. Stop valve closed.

The following should be checked:

a. Adequate steam supply.

b. Check steam supply system.

c. Check control valve actuator and drain valve operation.

d. Check that instrument air supply is of sufficient pressure and/or solenoid control valve operation.

Alarm and shutdown conditions of the steam injection system are detected by a protection program built into the micro-computer. Alarm and trip indications are displayed on the turbine panel CRT scope. An alarm condition is initiated by high or low pressure levels and by high or low temperatures. See Control Specification for alarm and trip point values.

The computer program is designed to trip the steam STOP valve and prevent steam flow if steam temperature becomes excessive. It can trip the system on temperature or pressure. Steam at too high a pressure can cause damage to valve stem packing and system seals. A steam injection trip only shuts down the steam injection system, it does not trip the turbine.

Certain trouble status indications can be displayed as messages on the CRT screen. Refer to the elementary diagram for alarm numbers and messages.

STEAM INJECTION SYSTEM

INFORMATION FOR THE COMPONENTS LISTED BELOW IS CONTAINED
IN THE ASSOCIATED PUBLICATION

COMPONENT	SYMBOL	MANUFACTURER	PUBLICATION
STEAM FLOW DIFFERENTIAL PRESSURE TRANSMITTER	96SJ-1 96AJ-1	ROSEMOUNT INC. MODEL 1151DP	4256/4257
STEAM INJECTION PRESSURE TRANSMITTER	96PJ-1 96PJ-2	ROSEMOUNT INC. MODEL 1151GP	4260/4261
STEAM CONTROL VALVE ASSEMBLY			
STEAM CONTROL VALVE WITH ACTUATOR AND ACCESSORIES	VA4-1 VA4-2	MASONEILAN DIV. MODEL 35-35202	EF-5000
	33CJ-1 33CJ-2	MASONEILAN DIV. SERIES 496	ES-7000
	90CJ-1	MASONEILAN DIV. SERIES 4600	ES-2000
STEAM STOP VALVE ASSEMBLY			
STEAM STOP VALVE WITH ACTUATOR AND ACCESSORIES	VS3-1 VS3-2	MASONEILAN DIV. MODEL 35-35202	EF-5000
	33SJ-2	MASONEILAN DIV. SERIES 496	ES-7000
	20SJ-1 20AJ-1,2	AUTOMATIC SWITCH CO.	V5688, V5380, V5551
	VPR27-2 VPR27-3	MASONEILAN DIV. MODEL 77-4	EY7700
DRAIN VALVE ASSEMBLY			
DRAIN VALVE, ACTUATOR AND ACCESSORIES	VD1-1, 2,4,5	MASONEILAN DIV. MODEL 35-35202	EF-5000
	33BS-1, 2,4,5	MASONEILAN DIV. MODEL 496	ES-7000
	20BS-1, 2,4,5	AUTOMATIC SWITCH CO. CAT HT8320A185	V-5688 & V-5380
	VPR46-1, 2,4,5	MASONEILAN DIV. MODEL 77-4	EY7700

BEST AVAILABLE COPY

NOX

GENERAL ELECTRIC 24785083 — CONT ON SHEET 2 SH NO 1

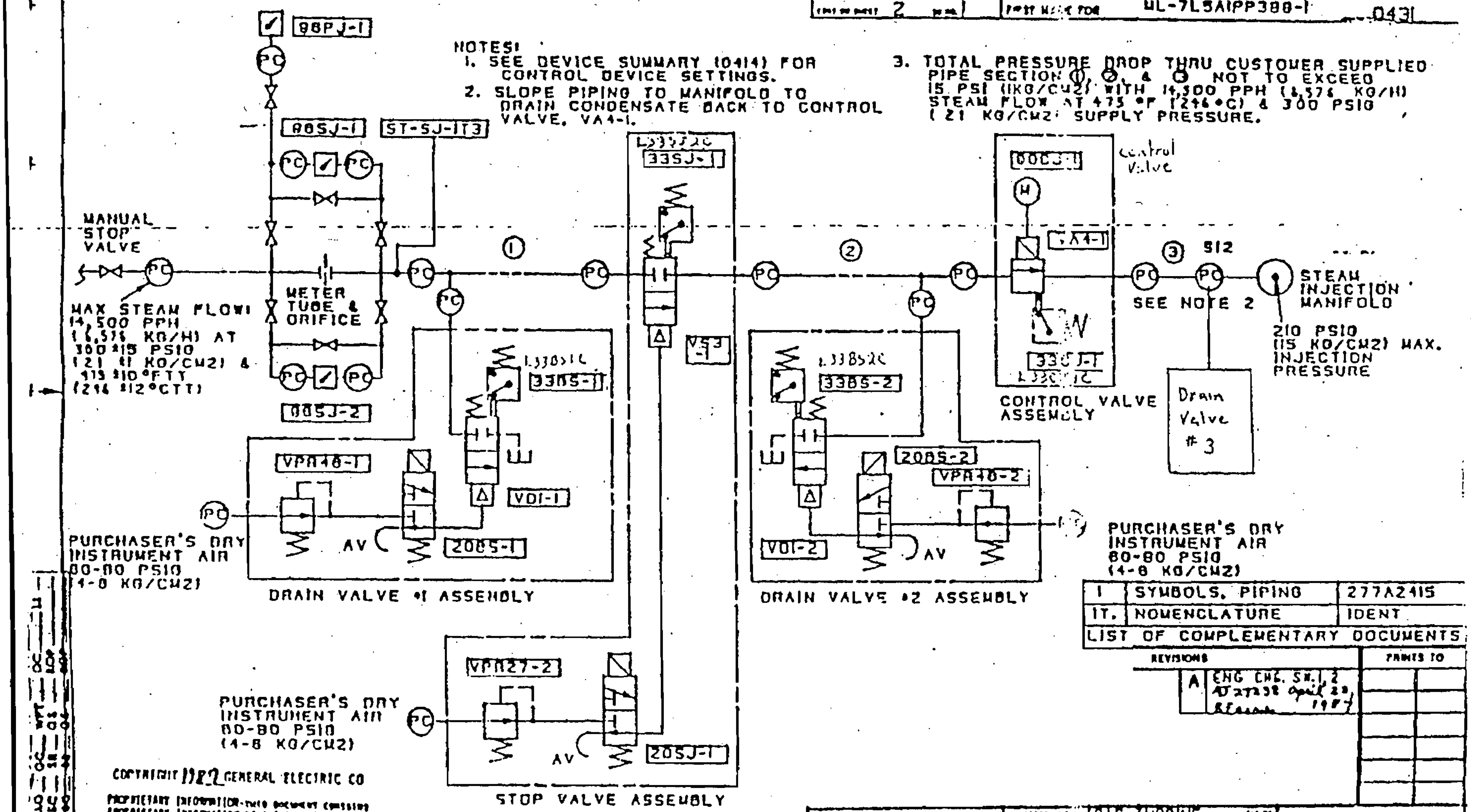
24785083 — CONT ON SHEET 2 SH NO 1

TITLE: DIAGRAM, SCHEM PP-ST INJECTION

FIRST MADE FOR: ML-7L5AIPP388-I 0431

NOTES:

1. SEE DEVICE SUMMARY (0414) FOR CONTROL DEVICE SETTINGS.
2. SLOPE PIPING TO MANIFOLD TO DRAIN CONDENSATE BACK TO CONTROL VALVE, VA4-1.
3. TOTAL PRESSURE DROP THRU CUSTOMER SUPPLIED PIPE SECTION ①, ②, & ③ NOT TO EXCEED 15 PSI (1KG/CM2) WITH 14,500 PPH (6,576 KG/H) STEAM FLOW AT 475 °F (246 °C) & 300 PSIG (21 KG/CM2) SUPPLY PRESSURE.



I	SYMBOLS, PIPING	277A2415
IT.	NOMENCLATURE	IDENT

LIST OF COMPLEMENTARY DOCUMENTS

REVISIONS		PRINTS TO
A	ENG CHG. SH. 1, 2 AD 27238 April 28 1987 Release	

Release 7/27/87 — March 31, 1987

GAS TURBINE — SCHENECTADY

24785083 — CONT ON SHEET 2 SH NO 1

REV. A 4/28/87

ATTACHMENT FPU-EU1-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

#9 AND #5 START-UP PROCEDURE

PURPOSE

This procedure has been written to provide a guide in starting up unit(s) #9 and #5 in a manner that will protect both operating personnel and equipment.

SCOPE

This procedure provides details on now to start-up the unit(s) and the order in which the start-ups should be performed.

This is a standard operating procedure aimed at providing uniformity during normal start-up. However, it does not take into account unforeseen problems which can alter the order in which these procedures are performed.

This list is not all inclusive and should not be relied on as a substitute for good operating practice based on individual training and experience.

POLICY

It is the policy of the Power Plant and FPUA to ensure the safety of personnel and equipment as effectively as possible, in this case, by providing operational guidelines for start-up of equipment.

GENERAL

This procedure will be used each time the unit(s) are put into service and will be signed off by the Watch Engineer and the Operators assisting in the equipment checkout procedures. It will then be turned into the Operations Supervisor.

RESPONSIBILITY

Watch Engineer

The Watch Engineer will oversee and supervise all aspects of unit(s) start-up, ensuring that Control/Boiler and Auxiliary Operators have checked and put equipment in operation safely and properly, and will assist when necessary.

The Watch Engineer will also make sure all motors 50 HP and above have been meggered, all permits are closed, tags removed, and breakers are racked in and ready for operation.

PREPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.
[illegible]	HP	POWER PLANT	10/92	0

RESPONSIBILITY (continued)

Control/Boiler and Auxiliary Operators

Operators will inspect and ensure that all equipment is in proper working order and ready for operation. Operators will notify the Watch Engineer of any abnormal conditions.

Operators will also inspect for tagged out items and breakers not racked in and ready for use and will notify the Watch Engineer if any of these conditions are found.

THE WATCH ENGINEER HAS THE AUTHORITY AND IS RESPONSIBLE FOR REMOVING TAGS AND CLOSING WORK PERMITS. UNDER NO CIRCUMSTANCES WILL AN OPERATOR REMOVE ANY TAG OR RACK IN ANY BREAKERS WITHOUT THE CONSENT AND/OR PRESENCE OF THE WATCH ENGINEER.

BEST AVAILABLE COPY

#9 AND #5 START-UP LIST

Date ________

PROCEDURES

		Checked By (Initials)
1.	MAKE SURE THAT ALL BREAKERS ON #9 ARE RACKED IN AND WORK PERMITS ARE CLOSED.	
2.	CHECK FIELD AND GENERATOR BREAKERS IN G.[illegible]	
3.	MAKE SURE GENERATOR HEATERS ARE ON.	
4.	MAKE SURE G.T. IS ON RATCHET - CALL GAS COMPANY.	
5.	IF STACK DAMPER TO BOILER IS NOT CLOSED - CLOSE IT.	
6.	VISUALLY CHECK G.T. FOR ANY UNUSUAL CONDITIONS THAT WOULD PREVENT SAFE OPERATION OF UNIT (OIL LEAKS, ETC.)	
7.	MAKE SURE YARD GAS VALVES AND MAIN GAS VALVE AT G.T. ARE OPEN.	
8.	TURN ON COALESCING UNIT FOR LUBE OIL SYSTEM.	
9.	CHECK ALARM PAGE ON G.T. FOR OUTSTANDING ALARMS.	
10.	MAKE SURE FUEL SELECTION IS ON GAS.	
11.	MAKE SURE YOU HAVE A START PERMISSIVE (PAGE 3A ON NET 90.)	
12.	TO START G.T. - PRESS AUTO, EXECUTE - THEN START, EXECUTE.	
13.	WHEN G.T. STARTS - OPEN DOORS AROUND UNIT AND CHECK FOR GAS LEAKS, HYDRAULIC LEAKS AND ABNORMAL CONDITIONS.	
14.	WHEN UNIT IS AT FULL SPEED - NO LOAD - SYNCHRONIZE UNIT (MANUAL OR AUTOMATIC) LOAD AS NEEDED. **NOTE** UNIT WILL NOT SYNCHRONIZE IF HYDRAULIC PUMP IS IN "HAND" POSITION.	
15.	CHECK FOR THINGS OVERLOOKED.	

NOTE: IF YOU ARE ONLY RUNNING #9 G.T. - STOP HERE.
CONTINUE ONLY IF YOU ARE GOING TO START-UP #5 UNIT.

PREPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.
9n / /	HD	POWER PLANT	10/92	0

#9 and #5 SHUTDOWN PROCEDURE

1 Take gas turbine off line by pressing gas turbine stop button at local controls.

2 Control room operator close the HRSG damper.

3 As #5 steam turbine rolls down, the control room operator must maintain proper generator voltage.

4 When the generator watthour meter stops, the control room operator must open the generator breaker and lower the generator voltage all the way down and open the field breaker.

5 When the generator is off line control room operator informs the shift supervisor and he/she will close the throttle valve stopping the turbine.

6 The auxiliary operator should maintain proper condenser/hotwell level during unit shutdown

7 Control room operator should maintain proper DA level and HRSG drum water levels.

ATTACHMENT FPU-EU1-IV1

IDENTIFICATION OF APPLICABLE REQUIREMENTS

ATTACHMENT FPU-EU1-IV1

IDENTIFICATION OF APPLICABLE REQUIREMENTS

A copy of the current Title V permit No. 1110003-005-AV is attached. A copy of the Acid Rain permit is also attached.

Fort Pierce Utilities Authority
H. D. King Power Plant
Facility ID No.: 1110003
St. Lucie County

Title V Air Operation Permit Renewal

FINAL Permit Project No.: 1110003-005-AV
Renewal of Title V Air Operation Permit No.: 1110003-003-AV

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation
Title V Section

Mail Station #5505
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Telephone: 850/488-0114
Fax: 850/922-6979

Compliance Authority:
Florida Department of Environmental Regulation
Southeast District
400 North Congress Avenue
P.O. Box 15425
West Palm Beach, Florida 33416-5425
Telephone: 561/681-6600
Fax: 561/681-6790

Title V Air Operation Permit Renewal

FINAL Permit No.: 1110003-005-AV
Renewal of Title V Air Operation Permit No.: 1110003-003-AV

Table of Contents

Section	**Page Number**

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

Permittee:
Fort Pierce Utilities Authority
P. O. Box 3191
Fort Pierce, Florida 34948

FINAL Permit No.: 1110003-005-AV
Facility ID No.: 1110003
SIC Nos.: 49, 4911
Project: Title V Air Operation Permit Renewal

The purpose of this permit is to renew Title V Air Operation Permit, No. 1110003-003-AV, and incorporate Administrative Corrections No. 1110003-006-AV, issued on February 28, 2000 and No. 1110003-007-AV, issued on September 20, 2000. This existing facility is located at 311 North Indian River Drive, Fort Pierce, St. Lucie County; UTM Coordinates: Zone 17, 566.8 km East and 3036.3 km North; Latitude: 27° 27' 00" North and Longitude: 80° 19' 26" West.

This Title V Air Operation Permit Renewal is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213 and 62-214. The above named permittee is hereby authorized to operate the facility shown on the application and approved drawing(s), plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit.

Referenced attachments made a part of this permit:
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
APPENDIX TV-4, TITLE V CONDITIONS version dated 02/12/02
APPENDIX SS-1, STACK SAMPLING FACILITIES version dated 10/07/96
TABLE 297.310-1, CALIBRATION SCHEDULE version dated 10/07/96
FIGURE 1 - SUMMARY REPORT-GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE REPORT version dated 07/96
Alternate Sampling Procedure: ASP Number 97-B-01
OGC Case No. 91-1610: Final Order filed 7/21/92

Effective Date: January 1, 2003
Renewal Application Due Date: July 5, 2007
Expiration Date: December 31, 2007

Joseph Kahn FOL

Howard L. Rhodes, Director
Division of Air Resource Management

HLR/sms/es

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of one 16.5 megawatt (electric) 219 million Btu per hour fossil fuel fired steam generator; one 37.5 megawatt (electric) 470 million Btu per hour fossil fuel fired steam generator; one 56.1 megawatt (electric) 611 million Btu per hour fossil fuel fired steam generator; and one 23.4 megawatt (electric) combined cycle gas turbine with a 8.2 megawatt (electric) heat recovery steam generator (HRSG).

Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the initial Title V Air Operation Permit application received July 8, 2002, this facility is not a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Unit ID No(s). and Brief Description(s).

E.U. ID No.	**Brief Description**
-003	23.4 MW Combined Cycle Gas Turbine with 8.2 MW HRSG - Unit #9
-004	16.5 MW Boiler - Unit #6
-007	37.5 MW Boiler - Unit #7
-008	56.1 MW Boiler - Unit #8

Unregulated Emissions Units and/or Activities

-001	2.75 MW West Diesel #1
-002	2.75 MW East Diesel #2
-009	Cooling Tower
-010	General Purpose Internal Combustion Engines

Please reference the Permit No., Facility ID No., and appropriate Emissions Unit(s) ID No(s). on all correspondence, test report submittals, applications, etc.

Subsection C. Relevant Documents.

The documents listed below are not a part of this permit; however, they are specifically related to this permitting action.

<u>These documents are provided to the permittee for information purposes only:</u>
Table 1-1: Summary of Air Pollutant Standards and Terms
Table 2-1: Summary of Compliance Requirements
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers
Appendix H-1, Permit History
Statement of Basis

<u>These documents are on file with the permitting authority:</u>
Initial Title V Air Operation Permit effective January 1, 1998
Title V Air Operation Permit Administrative Correction issued February 28, 2000
Title V Air Operation Permit Revision issued May 25, 2000
Title V Air Operation Permit Administrative Correction issued September 20, 2000
Application for a Title V Air Operation Permit Renewal received July 8, 2002
Additional Information Request dated July 25, 2002
Additional Information Response received September 3, 2002
Letter received October 15, 2002, from Mr. George Miller

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-4, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-4, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

2. Not federally enforceable. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

3. General Particulate Emission Limiting Standards. General Visible Emissions Standard.
Except for emissions units that are subject to a particulate matter or opacity limit set forth or established by rule and reflected by conditions in this permit, no person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity, the density of which is equal to or greater than that designated as Number 1 on the Ringelmann Chart (20 percent opacity). EPA Method 9 is the method of compliance pursuant to Chapter 62-297, F.A.C.
[Rules 62-296.320(4)(b)1. & 4., F.A.C.]

4. Prevention of Accidental Releases (Section 112(r) of CAA).
a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to:

RMP Reporting Center
Post Office Box 3346
Merrifield, VA 22116-3346
Telephone: 703/816-4434

and,
b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.
[40 CFR 68]

5. Unregulated Emissions Units and/or Activities. Appendix U-1, List of Unregulated Emissions Units and/or Activities, is a part of this permit.
[Rule 62-213.440(1), F.A.C.]

6. Insignificant Emissions Units and/or Activities. Appendix I-1, List of Insignificant Emissions Units and/or Activities, is a part of this permit.
[Rules 62-213.440(1), 62-213.430(6) and 62-4.040(1)(b), F.A.C.]

7. General Pollutant Emission Limiting Standards. Volatile Organic Compounds Emissions or Organic Solvents Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. **Nothing was deemed necessary and ordered at this time.**
[Rule 62-296.320(1)(a), F.A.C.]

8. Not federally enforceable. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include: paved fuel delivery roads and parking lots.
[Rule 62-296.320(4)(c)2., F.A.C.; and, proposed by applicant in the Title V Air Operation Permit Renewal application received July 8, 2002]

9. When appropriate, any recording, monitoring, or reporting requirements that are time-specific shall be in accordance with the effective date of the permit, which defines day one.
[Rule 62-213.440, F.A.C.]

10. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3)(a)2., F.A.C., shall be submitted to the Department and EPA within 60 (sixty) days after the end of the calendar year using DEP Form No. 62-213.900(7), F.A.C.
[Rules 62-213.440(3) and 62-213.900, F.A.C.]

{Permitting Note: This condition implements the requirements of Rules 62-213.440(3)(a)2. & 3., F.A.C. (see Condition 51. of APPENDIX TV-4, TITLE V CONDITIONS.)}

11. The permittee shall submit all compliance related notifications and reports required of this permit to the Department's Southeast District office:

Florida Department of Environmental Regulation
Southeast District
400 North Congress Avenue
P.O. Box 15425
West Palm Beach, Florida 33416-5425
Telephone: 561/681-6600; Fax: 561/681-6790

12. Any reports, data, notifications, certifications, and requests required to be sent to the United States Environmental Protection Agency, Region 4, should be sent to:

United States Environmental Protection Agency
Region 4
Air, Pesticides & Toxics Management Division
Air and EPCRA Enforcement Branch
Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303-8960
Telephone: 404/562-9155; Fax: 404/562-9163

13. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information.
[Rule 62-213.420(4), F.A.C.]

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
-003	23.4 MW Combined Cycle Gas Turbine with 8.2 MW HRSG - Unit #9

Unit #9 is a combined cycle gas turbine and a HRSG with a maximum heat input of 415 million Btu per hour. The HRSG is not supplementary-fired. The turbine is capable of producing 23.4 megawatts and the HRSG is capable of producing 8.2 megawatts of electric power. The primary fuel is natural gas with No. 2 fuel oil used as a backup fuel.

{Permitting notes: IMPORTANT REGULATORY CLASSIFICATIONS - The emissions unit is regulated under NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C. Combined cycle gas turbine #9 began commercial operation in May, 1990.}

The following specific conditions apply to the emissions unit(s) listed above:

<u>Essential Potential to Emit (PTE) Parameters</u>

A.1. <u>Permitted Capacity.</u> The maximum process/operation rate is 415 MMBtu per hour (lower heating value) heat input.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

A.2. <u>Emissions Unit Operating Rate Limitation After Testing</u>. See specific condition **A.25.**
[Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation. Fuels.
a. This emissions unit fires natural gas as the primary fuel.
b. This emissions unit fires No. 2 distillate oil as the emergency back-up fuel.
[Rules 62-210.200(PTE), 62-212.400, and 62-212.410, F.A.C.; and, AC 56-141460]

{Permitting note: Emergency backup fuel use is authorized for maintenance, as per manufacturer's specifications, and during restricted availability of natural gas.}

A.4. Hours of Operation. This emissions unit may operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

{Permitting note: Unless otherwise specified, the averaging time for conditions A.5. - A.9. are based on the specified averaging time of the applicable test method.}

A.5. Nitrogen Oxides. The NO_X emissions shall not exceed: STD = 0.0075 (14.4)/Y + F

where:

STD = allowable NO_X emissions (percent by volume at 15 percent oxygen on a dry basis).
Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.
F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph 40 CFR 60.332(a)(3).

or 84 ppmv at 15 percent oxygen on a dry basis.
[40 CFR 60.332(a)(1); and, AC 56-141460]

A.6. Sulfur Dioxide. Sulfur dioxide gases discharged to the atmosphere shall not exceed 0.015 percent by volume at 15 percent oxygen on a dry basis.
[40 CFR 60.333(a); and, AC 56-141460]

A.7. Sulfur Dioxide - Sulfur Content. The maximum sulfur content of the No. 2 distillate oil shall not exceed 0.5 percent by weight.
[AC 56-141460]

A.8. Visible Emissions. Visible emissions shall not exceed 15 percent opacity.
[AC 56-141460]

A.9. Carbon Monoxide. Carbon Monoxide emissions shall not exceed 32.85 pounds per hour and 110.4 tons per year.
[AC 56-141460]

Excess Emissions

A.10. Excess emissions from this emissions unit resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

A.11. 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.
[Rule 62-210.700(4), F.A.C.]

A.12. At all times, including periods of startup, shutdown and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
[40 CFR 60.11(d)]

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}

Monitoring of Operations

A.13. The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG and using steam injection to control NO_X emissions shall operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of steam to fuel being fired in the turbine. This system shall be accurate to within $\pm$5.0 percent and shall be approved by the Administrator.
[40 CFR 60.334(a); and, AC 56-141460]

A.14. The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:
(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.
(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel

supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with 40 CFR 60.334(b).
[40 CFR 60.334(b)(1) & (2)]

A.15. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, 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) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine 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.]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

A.16. To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Department to determine the nitrogen content of the fuel being fired.
[40 CFR 60.335(a)]

A.17. During performance tests to determine compliance, measured NO_X emissions at 15 percent oxygen will be adjusted to ISO ambient atmospheric conditions by the following correction factor:

$$NO_X = [NO_X\,obs]\,[(P_{ref})/P_{obs}]^{0.5}\ e^{19(H_{obs} - 0.00633)}\ [288^{o}\,K / T_{amb}]^{1.53}$$

where:
NO_X = Emissions of NO_X at 15 percent oxygen and ISO standard ambient conditions.

NO_X obs = Measured NO_X emission at 15 percent oxygen, ppmv.

P_{ref} = Reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure.

P_{obs} = Measured combustor inlet absolute pressure at test ambient pressure.

e = Transcendental constant (2.718)

H_{obs} = Specific humidity of ambient air at test.

T_{amb} = Temperature of ambient air at test.
[40 CFR 60.335(c)(1); and , AC 56-141460]

A.18. When determining compliance with 40 CFR 60.332, Subpart GG - Standards of Performance for Stationary Gas Turbines, the monitoring device of 60.334(a) shall be used to determine the fuel consumption and the steam-to-fuel ratio necessary to comply with the permitted NO_X standard at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.
[40 CFR 60.335(c)(2)]

A.19. The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 as follows:
c. U.S. EPA Method 20 (40 CFR 60, Appendix A) shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NO_X emissions shall be determined at each of the load conditions specified in 40 CFR 60.335(c)(2).
[40 CFR 60.335(c)(3)]

A.20. The owner or operator may determine compliance with the sulfur dioxide standard by calculations based on the fuel analysis for sulfur content. Certified analyses by the appropriate test method from the fuel supplier is acceptable. See specific condition **A.21.**
[AC 56-141460A]

A.21. The fuel sulfur content of 0.5 percent, by weight, shall be evaluated using ASTM D1552, ASTM D1072, ASTM D3031, ASTM D4084, or ASTM D3246, or latest edition. See specific condition **A.7.**
[AC 56-141460A]

A.22. To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in 40 CFR 60.335 (a) and 40 CFR 60.335(d) of 40 CFR 60.335 to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency. See specific condition **A.14.**
[40 CFR 60.335(e)]

A.23. Visible Emissions. The test method for visible emissions shall be EPA Method 9, incorporated by reference in Chapter 62-297, F.A.C.
[AC 56-141460]

A.24. Carbon Monoxide. The test method for carbon monoxide shall be EPA Method 10, incorporated by reference in Chapter 62-297, F.A.C.
[AC 56-141460]

A.25. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity (i.e., at less than 90 percent of the maximum operation rate allowed by the permit); in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted, provided however, operations do not exceed 100 percent of the maximum operation rate allowed by the permit. Once the emissions unit is so limited,

operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rule 62-297.310(2), F.A.C. and 1110003-002-AO]

A.26. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

A.27. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

A.28. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached to this permit.

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

A.29. The permittee shall comply with the requirements contained in APPENDIX SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

A.30. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a. Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 -- September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard;

b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

8. Any combustion turbine that does not operate for more than 400 hours per year shall conduct a visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.
(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable

weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.; and, SIP approved]

Record Keeping and Reporting Requirements

A.31. For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:
Nitrogen oxides. Any one-hour period during which the average steam-to-fuel ratio, as measured by the continuous monitoring system, falls below the steam-to-fuel ratio determined to demonstrate compliance with the permitted nitrogen oxide standard by the initial performance test required in 40 CFR 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the initial performance test. Each report shall include the average steam-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).
[Rule 62-296.800, F.A.C.; and, 40 CFR 60.334(c)(1)]

A.32. The owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form [see 40 CFR 60.7(d)] to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or, the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or, the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

[40 CFR 60.7(c)(1), (2), (3), & (4)]

A.33. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.

(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.

[40 CFR 60.7(d)(1) & (2)]

A.34. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department 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.
[Rule 62-210.700(6), F.A.C.]

A.35. All recorded data shall be maintained on file by the Source for a period of five years.
[Rule 62-213.440, F.A.C.]

A.36. Test Reports.

(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.

10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

Miscellaneous Requirements.

A.37. Definitions. For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60, shall apply except that the term "Administrator" when used in 40 CFR 60, shall mean the Secretary or the Secretary's designee.
[40 CFR 60.2; and, Rule 62-204.800(7)(a), F.A.C.]

A.38. Circumvention. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.
[40 CFR 60.12]

Section III. Emissions Unit(s) and Conditions.

Subsection B. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
-004	16.5 MW Boiler - Unit #6

Fossil fuel fired steam generator # 6 is a nominal 16.5 megawatt (electric) steam generator designated as H. D. King Unit # 6. The emission unit is fired on natural gas with a maximum heat input of 218.9 MMBtu per hour. No. 2 fuel oil is fired as a secondary/emergency fuel.

{Permitting note(s): The emissions unit is regulated under Rule 62-296.406, F.A.C., Fossil Fuel Steam Generators with Less than 250 million Btu per Hour Heat Input. Fossil fuel fired steam generator #6 began commercial operation in 1958.}

The following specific conditions apply to the emissions unit listed above:

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum operation heat input rate is as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
6	218.9	Natural Gas
	218.9	No. 2 Fuel Oil

See specific condition **E.1.**
[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.406, F.A.C.; OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

B.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **B.26.**
[Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation. Fuels.
a. This emissions unit fires natural gas as the primary fuel.
b. This emissions unit fires No. 2 fuel oil as the emergency back-up fuel.
The use of No. 2 fuel oil is limited. See specific conditions **B.36.** and **E.2.**
[Rule 62-213.410, F.A.C.; OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

{Permitting note: Unless otherwise specified, the averaging time for conditions B.5. - B.12. are based on the specified averaging time of the applicable test method.}

B.4. Hours of Operation. This emissions unit may operate continuously, i.e., 8,760 hours/year. See specific condition **E.1.**
[Rule 62-210.200(PTE), F.A.C.; and, OGC Case No. 91-1610: Final Order filed 7/21/92]

B.5. Visible Emissions. Visible emissions shall not exceed 5 percent opacity when firing natural gas. Visible emissions shall not exceed 20 percent opacity when firing fuel oil, except for one two-minute period per hour during which opacity shall not exceed 40 percent.
[OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

B.6. Visible emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.
[Rule 62-210.700(3), F.A.C.]

B.7. Particulate Matter. Particulate Matter emissions shall not exceed 0.4 pound per hour when firing natural gas and 0.1 pound per million Btu when firing No. 2 fuel oil. See specific condition **E.3.**
[OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

B.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. See specific condition **E.3.**
[Rule 62-210.700(3), F.A.C.]

B.9. Sulfur Dioxide. Sulfur Dioxide emissions shall not exceed 2.5 pounds per hour when firing natural gas and 0.80 pound per million Btu heat input when firing No. 2 fuel oil. See specific condition **E.3.**
[AC 56-141460A; OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

B.10. Nitrogen Oxides. Nitrogen Oxides emissions shall not exceed 1.31 pounds per hour when firing natural gas. See specific condition **E.3.**
[OGC Case No. 91-1610: Final Order filed 7/21/92]

B.11. Volatile Organic Compounds. Volatile Organic Compounds emissions shall not exceed 0.0236 pound per hour when firing natural gas. See specific condition **E.3.**
[OGC Case No. 91-1610: Final Order filed 7/21/92]

B.12. Carbon Monoxide. Carbon Monoxide emissions shall not exceed 0.15 pound per hour when firing natural gas. See specific condition **E.3.**
[OGC Case No. 91-1610: Final Order filed 7/21/92]

Excess Emissions

B.13. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

B.14. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

B.15. 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.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

B.16. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, 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) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine 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.]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

B.17. Visible emissions. The test method for visible emissions shall be EPA Method 9 when firing natural gas and DEP Method 9 when firing No. 2 fuel oil, incorporated in Chapter 62-297, F.A.C. See specific condition **B.18.**
[Rules 62-213.440 and 62-297.401, F.A.C.; OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

B.18. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:
1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.
2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:
   a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.
   b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rule 62-297.401, F.A.C.]

B.19. Particulate Matter. The test method for particulate matter shall be EPA Method 5, incorporated in Chapter 62-297, F.A.C.
[AC 56-141460A]

B.20. Sulfur Dioxide. The test method for sulfur dioxide shall be EPA Method 6 or 6C, incorporated in Chapter 62-297, F.A.C., or by calculation based on fuel analysis for sulfur content of the oil and natural gas. Certified analyses by the appropriate test method(s) from the fuel supplier is acceptable. See specific condition **B.21.**
[AC 56-141460A]

B.21. The fuel sulfur content of the oil or natural gas shall be evaluated using ASTM D1552, ASTM D1072, ASTM D3031, ASTM D4084, or ASTM D3246, or latest edition.
[AC 56-141460A]

B.22. The test method for nitrogen oxides shall be EPA Method 7 or 7E, incorporated in Chapter 62-297, F.A.C.
[AC 56-141460A]

B.23. The test method for volatile organic compounds shall be EPA Method 25A, incorporated in Chapter 62-297, F.A.C.
[AC 56-141460A]

B.24. The test method for carbon monoxide shall be EPA Method 10, incorporated in Chapter 62-297, F.A.C.
[AC 56-141460A]

B.25. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

B.26. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

B.27. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

B.28. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached to this permit.
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

B.29. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

B.30. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.
2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting

standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a. Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard;

b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid fuel, other than during startup, for a total of more than 400 hours.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; and, SIP approved]

B.31. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

[Rule 62-297.310(7)(a)4., F.A.C.]

B.32. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

[Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

Record keeping and Reporting Requirements

B.33. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department 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.
[Rule 62-210.700(6), F.A.C.]

B.34. All recorded data shall be maintained on file by the Source for a period of five years.
[Rule 62-213.440, F.A.C.]

B.35. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.

7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

B.36. The permittee must notify the DEP within 24 hours after commencement of oil firing and furnish the following information:

a. Duration or projected duration of the event.
b. Quantity of fuel oil burned or projected to be burned.
c. A description of significant circumstances precipitating the event, which shall include:
   (1) Availability of power for purchase
   (2) Availability of electric transmission capacity relating to power purchases
   (3) Availability of natural gas
   (4) Availability of the permittee's generation sources

[OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

Section III. Emissions Unit(s) and Conditions.

Subsection C. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
-007	37.5 MW Boiler - Unit #7

Fossil fuel fired steam generator # 7 is a nominal 37.5 megawatt (electric) steam generator designated as H. D. King Unit # 7. The emission unit is fired on natural gas with a maximum heat input of 470.0 MMBtu per hour. No. 2 fuel oil is fired as a secondary/emergency fuel. Emissions are discharged through a multicyclone collector.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input. Fossil fuel fired steam generator #7 began commercial operation in 1964.}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

C.1. Permitted Capacity. The maximum operation heat input rate is as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
7	470.0	Natural Gas
	470.0	No. 2 Fuel Oil

See specific condition **E.1.**
[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.406, F.A.C.; OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

C.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **C.26.**
[Rule 62-297.310(2), F.A.C.]

C.3. Methods of Operation. Fuels.
a. This emissions unit fires natural gas as the primary fuel.
b. This emissions unit fires No. 2 fuel oil as the emergency back-up fuel.
The use of No. 2 fuel oil is limited. See specific conditions **C.37.** and **E.2.**
[Rule 62-213.410, F.A.C.; OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

C.4. Hours of Operation. This emissions unit may operate continuously, i.e., 8,760 hours/year. See specific condition **E.1.**
[Rule 62-210.200(PTE), F.A.C.; and, OGC Case No. 91-1610: Final Order filed 7/21/92]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

{Permitting note: Unless otherwise specified, the averaging time for conditions C.5. - C.12 are based on the specified averaging time of the applicable test method.}

C.5. Visible Emissions. Visible emissions shall not exceed 5 percent opacity when firing natural gas. Visible emissions shall not exceed 20 percent opacity when firing fuel oil, except for one two-minute period per hour during which opacity shall not exceed 40 percent.
[OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

C.6. Visible emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.
A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.
[Rule 62-210.700(3), F.A.C.]

C.7. Particulate Matter. Particulate Matter emissions shall not exceed 0.568 pound per hour when firing natural gas and 0.1 pound per million Btu when firing No. 2 fuel oil. See specific condition **E.3.**
[OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

C.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. See specific condition **E.3.**
[Rule 62-210.700(3), F.A.C.]

C.9. Sulfur Dioxide. Sulfur Dioxide emissions shall not exceed 2.5 pounds per hour when firing natural gas and 0.80 pound per million Btu heat input when firing No. 2 fuel oil. See specific condition **E.3.**
[AC 56-141460A; OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

C.10. Nitrogen Oxides. Nitrogen Oxides emissions shall not exceed 104.35 pounds per hour when firing natural gas. See specific condition **E.3.**
[OGC Case No. 91-1610: Final Order filed 7/21/92]

C.11. Volatile Organic Compounds. Volatile Organic Compounds emissions shall not exceed 0.266 pound per hour when firing natural gas. See specific condition **E.3.**
[OGC Case No. 91-1610: Final Order filed 7/21/92]

C.12. Carbon Monoxide. Carbon Monoxide emissions shall not exceed 7.589 pounds per hour when firing natural gas. See specific condition **E.3.**
[OGC Case No. 91-1610: Final Order filed 7/21/92]

Excess Emissions

C.13. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

C.14. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

C.15. 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.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

C.16. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, 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) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine 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.]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

C.17. Visible emissions. The test method for visible emissions shall be EPA Method 9 when firing natural gas and DEP Method 9 when firing No. 2 fuel oil, incorporated in Chapter 62-297, F.A.C. See specific condition **C.18.**
[Rules 62-213.440 and 62-297.401, F.A.C.; and, OGC Case No. 91-1610: Final Order filed 7/21/92]

C.18. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:
1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.
2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:
  a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.
  b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rule 62-297.401, F.A.C.]

C.19. Particulate Matter. The test method for particulate matter shall be EPA Method 5, incorporated in Chapter 62-297, F.A.C.
[AC 56-141460A]

C.20. Sulfur Dioxide. The test method for sulfur dioxide shall be EPA Method 6 or 6C, incorporated in Chapter 62-297, F.A.C., or by calculation based on fuel analysis for sulfur content of the oil and natural gas. Certified analyses by the appropriate test method(s) from the fuel supplier is acceptable. See specific condition **C.21.**
[AC 56-141460A]

C.21. The fuel sulfur content of the oil or natural gas shall be evaluated using ASTM D1552, ASTM D1072, ASTM D3031, ASTM D4084, or ASTM D3246, or latest edition.
[AC 56-141460A]

C.22. The test method for nitrogen oxides shall be EPA Method 7 or 7E, incorporated in Chapter 62-297, F.A.C.
[AC 56-141460A]

C.23. The test method for volatile organic compounds shall be EPA Method 25A, incorporated in Chapter 62-297, F.A.C.
[AC 56-141460A]

C.24. The test method for carbon monoxide shall be EPA Method 10, incorporated in Chapter 62-297, F.A.C.
[AC 56-141460A]

C.25. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

C.26. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

C.27. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

C.28. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached to this permit.
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

C.29. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

C.30. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.
2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting

standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

a. Did not operate; or

b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

a. Visible emissions, if there is an applicable standard;

b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

c. Each NESHAP pollutant, if there is an applicable emission standard.

5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid fuel, other than during startup, for a total of more than 400 hours.

9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

[Rule 62-297.310(7), F.A.C.; and, SIP approved]

C.31. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or

b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or

c. only liquid fuel(s) for less than 400 hours per year.

[Rule 62-297.310(7)(a)4., F.A.C.]

C.32. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or

b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or

c. only liquid fuel(s) for less than 400 hours per year.

[Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

Record keeping and Reporting Requirements

C.33. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department 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.
[Rule 62-210.700(6), F.A.C.]

C.34. All recorded data shall be maintained on file by the Source for a period of five years.
[Rule 62-213.440, F.A.C.]

C.35. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

C.36. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.

9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

C.37. The permittee must notify the DEP within 24 hours after commencement of oil firing and furnish the following information:

a. Duration or projected duration of the event.
b. Quantity of fuel oil burned or projected to be burned.
c. A description of significant circumstances precipitating the event, which shall include:
   (1) Availability of power for purchase
   (2) Availability of electric transmission capacity relating to power purchases
   (3) Availability of natural gas
   (4) Availability of the permittee's generation sources

[OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

Section III. Emissions Unit(s) and Conditions.

Subsection D. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
-008	56.1 MW Boiler - Unit #8

H. D. King Unit #8 is a nominal 56.1 megawatt (electric) fossil fuel fired steam generator. The emission unit is fired on natural gas with a maximum heat input of 644.0 MMBtu per hour. No. 2 fuel oil is fired as a secondary/emergency fuel. Emissions are uncontrolled.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; and NSPS - 40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C. Fossil fuel fired steam generator # 8 began commercial operation in May 1976.}

The following specific conditions apply to the emissions unit(s) listed above:

Essential Potential to Emit (PTE) Parameters

D.1. Permitted Capacity. The maximum operation heat input rate is as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
8	644.0	Natural Gas
	644.0	No. 2 Fuel Oil

See specific condition **E.1.**
[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.406, F.A.C.; OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. Rule 62-297.310(5), F.A.C., included in the permit, requires measurement of the process variables for emission tests. Such heat input determination may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heat value of the fuel determined by the fuel vendor or the owner or operator, to calculate average hourly heat input during the test.}

D.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **D.26.**
[Rule 62-297.310(2), F.A.C.]

D.3. Methods of Operation. Fuels.
a. This emissions unit fires natural gas as the primary fuel.
b. This emissions unit fires No. 2 fuel oil as the emergency back-up fuel.
The use of No. 2 fuel oil is limited. See specific conditions **D.45.** and **E.2.**
[Rule 62-213.410, F.A.C.; OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

D.4. Hours of Operation. This emissions unit may operate continuously, i.e., 8,760 hours/year and shall meet the requirements of specific condition **E.1.** See specific condition **E.1.**
[Rule 62-210.200(PTE), F.A.C.; and, OGC Case No. 91-1610: Final Order filed 7/21/92]

Emission Limitations and Standards

{Permitting note: Table 1-1, Summary of Air Pollutant Standards and Terms, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

{Permitting note: Unless otherwise specified, the averaging time for conditions D.5. - D.12. are based on the specified averaging time of the applicable test method.}

D.5. Visible Emissions. Visible emissions shall not exceed 5 percent opacity when firing natural gas. Visible emissions shall not exceed 20 percent opacity when firing fuel oil, except for one six-minute period per hour during which opacity shall not exceed 27 percent.
[40 CFR 60.42(a)(2); OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

D.6. Visible emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.
[Rule 62-210.700(3), F.A.C.]

D.7. Particulate Matter. Particulate Matter emissions shall not exceed 0.945 pound per hour when firing natural gas and 0.1 pound per million Btu when firing No. 2 fuel oil. See specific condition **E.3.**
[OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

D.8. Particulate Matter - Soot Blowing and Load Change. Particulate matter emissions shall not exceed an average of 0.3 pound per million Btu heat input during the 3-hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change. See specific condition **E.3.**
[Rule 62-210.700(3), F.A.C.]

D.9. Sulfur Dioxide. Sulfur Dioxide emissions shall not exceed 2.5 pounds per hour when firing natural gas and 0.80 pound per million Btu heat input when firing No. 2 fuel oil. See specific condition **E.3.**
[AC 56-141460A; OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

D.10. Nitrogen Oxides. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:
(1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.
(2) 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel.
See specific condition **E.3.**
[40 CFR 60.44(a)(1) & (2); and, OGC Case No. 91-1610: Final Order filed 7/21/92]

D.11. Volatile Organic Compounds. Volatile Organic Compounds emissions shall not exceed 0.441 pound per hour when firing natural gas. See specific condition **E.3.**
[OGC Case No. 91-1610: Final Order filed 7/21/92]

D.12. Carbon Monoxide. Carbon Monoxide emissions shall not exceed 12.59 pounds per hour when firing natural gas. See specific condition **E.3.**
[OGC Case No. 91-1610: Final Order filed 7/21/92]

Excess Emissions

D.13. Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:
(1) Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported
(3) Nitrogen oxides. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under 40 CFR 60.44.
[40 CFR 60.45(g)(1) & (3)]

D.14. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

D.15. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

D.16. 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.
[Rule 62-210.700(4), F.A.C.]

{Permitting note: The Excess Emissions Rule at Rule 62-210.700, F.A.C., cannot vary any requirement of a NSPS, NESHAP, or Acid Rain program provision.}

Monitoring of Operations

D.17. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, 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) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine 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.]

Test Methods and Procedures

{Permitting note: Table 2-1, Summary of Compliance Requirements, summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.}

D.18. Visible emissions. The test method for visible emissions shall be EPA Method 9 when firing natural gas and DEP Method 9 when firing No. 2 fuel oil, incorporated in Chapter 62-297, F.A.C. See specific condition **D.19.**
[Rules 62-213.440 and 62-297.401, F.A.C.; OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

D.19. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:
1. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.
2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:
   a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.

b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.
In order to be valid, any required average (i.e., a six-minute or two-minute average) shall be based on all of the valid observations in the sequential subset of observations selected, and the selected subset shall contain at least 90 percent of the observations possible for the required averaging time. Each required average shall be calculated by summing the opacity value of each of the valid observations in the appropriate subset, dividing this sum by the number of valid observations in the subset, and rounding the result to the nearest whole number. The number of missing observations in the subset shall be indicated in parenthesis after the subset average value.
[Rule 62-297.401, F.A.C.]

D.20. Particulate Matter. The test method for particulate matter shall be EPA Method 5, incorporated in Chapter 62-297, F.A.C.
[AC 56-141460A]

D.21. Sulfur Dioxide. The test method for sulfur dioxide shall be EPA Method 6 or 6C, incorporated in Chapter 62-297, F.A.C., or by calculation based on fuel analysis for sulfur content of the oil and natural gas. Certified analyses by the appropriate test method(s) from the fuel supplier is acceptable. See specific condition **D.22.**
[AC 56-141460A]

D.22. The fuel sulfur content of the oil or natural gas shall be evaluated using ASTM D1552, ASTM D1072, ASTM D3031, ASTM D4084, or ASTM D3246, or latest edition.
[AC 56-141460A]

D.23. The test method for nitrogen oxides shall be EPA Method 7 or 7E, incorporated in Chapter 62-297, F.A.C.
[AC 56-141460A]

D.24. The test method for volatile organic compounds shall be EPA Method 25A, incorporated in Chapter 62-297, F.A.C.
[AC 56-141460A]

D.25. The test method for carbon monoxide shall be EPA Method 10, incorporated in Chapter 62-297, F.A.C.
[AC 56-141460A]

D.26. The owner or operator shall determine compliance with the particulate matter, SO_2, and NO_X standards as follows:
(1) The emission rate (E) of particulate matter, SO_2, or NO_X shall be computed for each run using the following equation:

$$E = C\,F_d\,(20.9)/(20.9 - \%\,O_2)$$

E = emission rate of pollutant, ng/J (lb/million Btu).
C = concentration of pollutant, ng/dscm (lb/dscf).
% O_2 = oxygen concentration, percent dry basis.
F_d = factor as determined from Method 19.

(2) Method 5 shall be used to determine the particular matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train may be set to provide a gas temperature no greater than 160 ± 14 °C (320 ± 25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration (%O_2). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all the individual O_2 sample concentrations at each traverse point.

(iii) If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points.

(3) Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity.

(4) Method 6 shall be used to determine the SO_2 concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration (%O_2). The O_2 sample shall be taken simultaneously with, and at the same point as, the SO_2 sample. The SO_2 emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 shall be used to determine the NO_X concentration.

(i) The sampling site and location shall be the same as for the SO_2 sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_X sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration (%O_2). The sample shall be taken simultaneously with, and at the same point as, the NO_X sample.

(iii) The NO_X emission rate shall be computed for each pair of NO_X and O_2 samples. The NO_X emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

[40 CFR 60.46(b)(1), (2), (3), (4), & (5)]

D.27. The owner or operator may use the following as alternatives to the reference methods and procedures in 40 CFR 60.46 or in other sections as specified:

(1) The emission rate (E) of particulate matter, SO_2 and NO_X may be determined by using the Fc factor, provided that the following procedure is used:

(i) The emission rate (E) shall be computed using the following equation:

$$E = C\, F_c\, (100 / \%\, CO_2)$$

where:

E = emission rate of pollutant, ng/J (lb/million Btu).

C = concentration of pollutant, ng/dscm (lb/dscf).

% CO_2 = carbon dioxide concentration, percent dry basis.

F_c = factor as determined in appropriate sections of Method 19.

(ii) If and only if the average F_c factor in Method 19 is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B shall be used to determine the O_2 and CO_2 concentration according to the procedures in 40 CFR 60.46(b)(2)(ii), (4)(ii), or (5)(ii). Then if F_o (average of three runs), as calculated from the equation in Method 3B, is more than ± 3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19, i.e., $F_{oa} = 0.209 (F_{da} / F_{ca})$, then the following procedure shall be followed:

(A) When F_o is less than 0.97 F_{oa}, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When F_o is less than 0.97 F_{oa} and when the average difference ($\bar{d}$) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When F_o is greater than 1.03 F_{oa} and when $\bar{d}$ is positive, then E shall be decreased by that proportion over 1.03 F_{oa}, e.g., if F_o is 1.05 F_{oa}, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (320 ° F). Method 17 shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and SO_2 may be determined simultaneously with the Method 5 train provided that the following changes are made:

(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 is used in place of the condenser (section 2.1.7) of Method 5.

(ii) All applicable procedures in Method 8 for the determination of SO_2 (including moisture) are used.

(4) For Method 6, Method 6C may be used. Method 6A may also be used whenever Methods 6 and 3B data are specified to determine the SO_2 emission rate, under the conditions in 40 CFR 60.46(d)(1).

(5) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O_2 concentration ($\%O_2$) for the emission rate correction factor.

(6) For Method 3, Method 3A or 3B may be used.

(7) For Method 3B, Method 3A may be used.

[40 CFR 60.46(d)(1), (2), (3), (4), (5), (6), & (7)]

D.28. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic

mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

D.29. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

D.30. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

D.31. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached to this permit.
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

D.32. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

D.33. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.
2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
a. Did not operate; or
b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.
4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
a. Visible emissions, if there is an applicable standard;
b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
c. Each NESHAP pollutant, if there is an applicable emission standard.
5. An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid fuel, other than during startup, for a total of more than 400 hours.
9. The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.
(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.
(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable

weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.; and, SIP approved]

D.34. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

[Rule 62-297.310(7)(a)4., F.A.C.]

D.35. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.

[Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

Continuous Monitoring Requirements

D.36. The owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring nitrogen oxide emissions, and oxygen or carbon dioxide.
[40 CFR 60.45(a) & (b)]

D.37. For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:
(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to 40 CFR 60.
(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
Gas................................	{1}	500
Liquid..............................	1,000	500
Solid...............................	1,500	1000
Combinations.........................	1,000y+1,500z	500(x+y)+1,000z

{1}Not applicable.

where:
x = the fraction of total heat input derived from gaseous fossil fuel, and
y = the fraction of total heat input derived from liquid fossil fuel, and
z = the fraction of total heat input derived from solid fossil fuel.

[40 CFR 60.45(c)(2) & (3)]

{Permitting note: The Stationary Source Compliance Division has determined that continuous emissions monitor (CEMs) requirements of 40 CFR Part 75 (Acid Rain) are equivalent to or more stringent than the requirements of 40 CFR Part 60 (NSPS). EPA and the Department do accept Acid Rain CEMs as NSPS CEMs provided that the utility demonstrates compliance with all applicable NSPS regulations. (Memorandum from John B. Rasnic, Director)}

D.38. For any continuous monitoring system installed under 40 CFR 60.45(a), the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):
(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$E = CF[20.9/(20.9\text{-percent } O_2)]$

where:

E, C, F, and % O_2 are determined under 40 CFR 60.45(f).

[40 CFR 60.45(e)(1)]

D.39. The values used in the equations under 40 CFR 60.45(e) (1) are derived as follows:
(1) E = pollutant emissions, ng/J (lb/million Btu).
(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for sulfur dioxide and 46.01 for nitrogen oxides.
(3) % O_2, % CO_2 = oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under 40 CFR 60.45(a).
(4) F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:
(iii) For liquid fossil fuels including crude, residual, and distillate oils, $F = 2.476 \times 10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_c = 0.384 \times 10^{-7}$ scm CO_2 /J (1,430 scf CO_2 /million Btu).
(iv) For gaseous fossil fuels, $F = 2.347 \times 10^{-7}$ dscm/J (8,740 dscf/million Btu). For natural gas, propane, and butane fuels, $F_c = 0.279 \times 10^{-7}$ scm CO_2 /J (1,040 scf CO_2 /million Btu) for natural gas, 0.322×10^{-7} scm CO_2 /J (1,200 scf CO_2/million Btu) for propane, and 0.338×10^{-7} scm CO_2 /J (1,260 scf CO_2 /million Btu) for butane.

(5) The owner or operator may use the following equation to determine an F factor (dscm/J or dscf/million Btu) on a dry basis (if it is desired to calculate F on a wet basis, consult the Administrator) or F_c factor (scm CO_2 /J, or scf CO_2 /million Btu) on either basis in lieu of the F or F_c factors specified in 40 CFR 60.45(f)(4):

$$F = 10^{-6}\frac{[227.2\ (\text{pct. H}) + 95.5\ (\text{pct. C}) + 35.6\ (\text{pct. S}) + 8.7\ (\text{pct. N}) - 28.7\ (\text{pct. O})]}{GCV}$$

$$F_c = \frac{2.0\text{x}10^{-5}\ (\text{pct. C})}{GCV}$$

(SI units)

$$F = 10^{6}\ \frac{3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)}{GCV}$$

(English units)

$$F_c = \frac{321\text{x}10^{3}\ (\%C)}{GCV}$$

(English units)

(i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM method D3178-74 or D3176 (solid fuels) or computed from results using ASTM method D1137-53(75), D1945-64(76), or D1946-77 (gaseous fuels) as applicable. (These five methods are incorporated by reference-see 40 CFR 60.17.)
(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015-77 for solid fuels and D1826-77 for gaseous fuels as applicable. (These two methods are incorporated by reference-see 40 CFR 60.17.)

(6) For affected facilities firing combinations of fossil fuels, the F or F_c factors determined by paragraphs 40 CFR 60.45(f)(4) or (f)(5) shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_iF_i \quad \text{or} \quad F_c = \sum_{i=1}^{n} X_i(F_c)_i$$

where:
X_i = the fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.)
F_i or $(F_c)_i$ = the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.
n = the number of fuels being burned in combination.
[40 CFR 60.45(f)(1), (2), (3), (4), (5), & (6)]

Recordkeeping and Reporting Requirements

D.40. Excess emission and monitoring system performance reports shall be submitted to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each excess emission and monitoring systems performance report shall include the information required in 40 CFR 60.7(c). The summary report form shall contain the information and be in the format shown in figure 1 (attached to this permit) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.
[40 CFR 60.7(d) & 60.45(g)]

D.41. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department 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.
[Rule 62-210.700(6), F.A.C.]

D.42. All recorded data shall be maintained on file by the Source for a period of five years.
[Rule 62-213.440, F.A.C.]

D.43. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

D.44. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.

9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rules 62-213.440 and 62-297.310(8), F.A.C.]

D.45. The permittee must notify the DEP within 24 hours after commencement of oil firing and furnish the following information:
a. Duration or projected duration of the event.
b. Quantity of fuel oil burned or projected to be burned.
c. A description of significant circumstances precipitating the event, which shall include:
   (1) Availability of power for purchase
   (2) Availability of electric transmission capacity relating to power purchases
   (3) Availability of natural gas
   (4) Availability of the permittee's generation sources

[OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

Miscellaneous Requirements.

D.46. Definitions. For the purposes of Rule 62-204.800(7), F.A.C., the definitions contained in the various provisions of 40 CFR 60, shall apply except that the term "Administrator" when used in 40 CFR 60, shall mean the Secretary or the Secretary's designee.
[40 CFR 60.2; and, Rule 62-204.800(7)(a), F.A.C.]

D.47. Circumvention. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.
[40 CFR 60.12]

Section III. Emissions Unit(s) and Conditions.

Subsection E. Common Conditions.

E.U. ID No.	**Brief Description**
-004	16.5 MW Boiler - Unit #6
-007	37.5 MW Boiler - Unit #7
-008	56.1 MW Boiler - Unit #8

The following conditions apply to the emissions units listed above:

Essential Potential to Emit (PTE) Parameters

E.1. The total combined heat input for Emissions Units -004, -007 and -008 (Units #6, #7, and #8) shall not exceed 4,534,930 million Btu per year.
[AC 56-141460, amended 11/9/90; and, OGC Case No. 91-1610: Final Order filed 7/21/92]

E.2. No. 2 fuel oil can be fired as a standby fuel for up to a combined total of 400 hours per year, when necessary in order to avoid curtailing electric power to its customers.
[OGC Case No. 91-1610: Final Order filed 7/21/92; and, applicant request dated 11/30/99]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging time for condition E.3. is based on the specified averaging time of the applicable test method.}

E.3. The total combined emissions from Emissions Units -004, -007 and -008 (Units #6, #7, and #8) shall not exceed:

PARAMETER	**TONS PER YEAR**
Particulate Matter	16.0
Sulfur Dioxide	101.6
Nitrogen Oxides	622.0
Volatile Organic Compounds	2.3
Carbon Monoxide	45.3

[OGC Case No. 91-1610: Final Order filed 7/21/92]

Section IV. This section is the Acid Rain Part.

Operated by: Fort Pierce Utilities Authority
ORIS code: 658

Subsection A. This subsection addresses Acid Rain, Phase II.

The emissions units listed below are regulated under Acid Rain Program, Phase II.

E.U. ID No.	Description
-007	37.5 MW Boiler - Unit #7
-008	56.1 MW Boiler - Unit #8

A.1. The Phase II permit application submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application(s) listed below:
a. DEP Form No. 62-210.900(1)(a), dated August 28, 2002
[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

A.2. Sulfur dioxide (SO_2) allowance allocations requirements for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID	Year	2003	2004	2005	2006	2007
-007	ID No. 07	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	63*	63*	63*	63*	63*
-008	ID No. 08	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	26*	26*	26*	26*	26*

*The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by the USEPA under Table 2 or 3 of 40 CFR 73.

A.3. Emission Allowances. Emissions from sources subject to the Federal Acid Rain Program (Title IV) shall not exceed any allowances that the source lawfully holds under the Federal Acid Rain Program. Allowances shall not be used to demonstrate compliance with a non-Title IV applicable requirement of the Act.
1. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Federal Acid Rain Program, provided that such increases do not require a permit revision pursuant to Rule 62-213.400(3), F.A.C.
2. No limit shall be placed on the number of allowances held by the source under the Federal Acid Rain Program.
3. Allowances shall be accounted for under the Federal Acid Rain Program.
[Rule 62-213.440(1)(c), F.A.C.]

A.4. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62- 214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, F.A.C., Fast-Track Revisions of Acid Rain Parts.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.5. Comments, notes, and justifications: none

A.6. Where an applicable requirement of the Act is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, both provisions shall be incorporated into the permit and shall be enforceable by the Administrator.
[40 CFR 70.6(a)(1)(ii); and, Rule 62-210.200, Definitions - Applicable Requirements, F.A.C.]

Appendix I-1: List of Insignificant Emissions Units and/or Activities.

Ft. Pierce Utilities Authority
H. D. King Power Plant

FINAL Permit No.: 1110003-005-AV
Facility ID No.: 1110003

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, or that meet the criteria specified in Rule 62-210.300(3)(b)1., F.A.C., Generic Emissions Unit Exemption, are exempt from the permitting requirements of Chapters 62-210, 62-212 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities

1. No. 2 Fuel Oil Storage Tank #5
2. Waste Oil Storage Tank
3. Compressed Nitrogen Bottles
4. Storage and Use of Water Treatment Chemicals
5. 55 Gallon Drum of Trichloroethylene and Percloroethylene
6. Lube Oil Storage
7. Parts Washer
8. Miscellaneous Painting Activities
9. Miscellaneous Welding Activities
10. Oil/Water Separator

Appendix U-1: List of Unregulated Emissions Units and/or Activities.

Ft. Pierce Utilities Authority
H. D. King Power Plant

FINAL Permit No.: 1110003-005-AV
Facility ID No.: 1110003

Unregulated Emissions Units and/or Activities. An emissions unit which emits no "emissions-limited pollutant" and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from unit-specific emissions or work practice standards.

The below listed emissions units and/or activities are neither 'regulated emissions units' nor 'insignificant emissions units'.

E.U. ID No.	Brief Description of Emissions Units and/or Activity
-001	2.75 MW West Diesel #1
-002	2.75 MW East Diesel #2
-009	Cooling Tower
-010	General Purpose Internal Combustion Engines

Table 1-1, Summary of Air Pollutant Standards and Terms

Ft. Pierce Utilities Authority
H. D. King Power Plant

FINAL Title V Permit Renewal No.: 1110003-005-AV
Facility ID No.: 1110003

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No.	**Brief Description**
[-003]	23.4 MW Combined Cycle Gas Turbine with 8.2 MW HRSG - Unit #9

			Allowable Emissions			Equivalent Emissions*			
Pollutant Name	Fuel(s)	Hours/Year	Standard(s)	lbs./hour	TPY	lbs./hour	TPY	Regulatory Citation(s)	See permit condition(s)
NO_x	All	8,760	STD=0.0075(14.4)/Y + F (Max 84 ppm)			135.69	592.69	40 CFR 60.332(a)(1) & AC 56-141460	A.5.
SO_2	All	8,760	0.015% vol @ 15% Oxygen			319.51	1,395.62	40 CFR 60.332(a)(1) & AC 56-141460	A.6.
SO_2	Oil	8,760	0.5% S by weight			319.51	1,395.62	AC 56-141460	A.7.
VE	All	8,760	Not to exceed 15%					AC 56-141460	A.8.
CO	All	8,760		32.85	110.4			AC 56-141460	A.9.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.

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Table 1-1, Summary of Air Pollutant Standards and Terms

Ft. Pierce Utilities Authority
H. D. King Power Plant

FINAL Title V Permit Renewal No.: 1110003-005-AV
Facility ID No.: 1110003

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No.	Brief Description
[-004]	16.5 MW Boiler - Unit #6

			Allowable Emissions			Equivalent Emissions*			
Pollutant Name	Fuel(s)	Hours/Year	Standard(s)	lbs./hour	TPY	lbs./hour	TPY	Regulatory Citation(s)	See permit condition(s)
VE	Gas	8,760	Not Exceed 5%					OGC Case#91-1610	B.5.
VE	Oil	8,760	20% except 40% 2 min/hr					OGC Case#91-1610	B.5
VE	All	8,760	60% 3 hrs/24 hrs					62-210.700(3), FAC	B.6.
PM	Gas	8,760		0.4	16.0**			OGC Case#91-1610	B.7. & E.3.
PM	Oil	400	0.1 lb/MMBtu		16.0**			OGC Case#91-1610	B.7. & E.3.
PM	Oil		0.3 lb/MMBtu 3hrs/24 hrs		16.0**			62-210.700(3), FAC	B.8. & E.3
SO_2	Gas	8,760		2.5	101.6**			OGC Case#91-1610	B.9. & E.3
SO_2	Oil	8,760	0.80 lb/MMBtu		101.6**			OGC Case#91-1610	B.9. & E.3.
NO_x	Gas	8,760		1.31	622.0**			OGC Case#91-1610	B.10. & E.3.
VOC	Gas	8,760		0.0236	2.3**			OGC Case#91-1610	B.11. & E.3.
CO	Gas	8,760		0.15	45.3**			OGC Case#91-1610	B.12. & E.3.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.
** The total combined emissions from EU [-004], [-007], and [-008]

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Table 1-1, Summary of Air Pollutant Standards and Terms

Ft. Pierce Utilities Authority
H. D. King Power Plant

FINAL Title V Permit Renewal No.:1110003-005-AV
Facility ID No.: 1110003

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit

E.U. ID No.	**Brief Description**
[-007]	37.5 MW Boiler - Unit #7

			Allowable Emissions			Equivalent Emissions*			
Pollutant Name	Fuel(s)	Hours/Year	Standard(s)	lbs./hour	TPY	lbs./hour	TPY	Regulatory Citation(s)	See permit condition(s)
VE	Gas	8,760	Not Exceed 5%					OGC Case#91-1610	C.5.
VE	Oil	8,760	20% except 40% 2 min/hr					OGC Case#91-1610	C.5.
VE	All	8,760	60% 3 hrs/24 hrs					62-210.700(3), FAC	C.6.
PM	Gas	8,760		0.568	16.0**			OGC Case#91-1610	C.7. & E.3.
PM	Oil		0.1 lb/MMBtu		16.0**			OGC Case#91-1610	C.7. & E.3.
PM	Oil		0 3 lb/MMBtu 3hrs/24 hrs		16.0**			62-210.700(3), FAC	C.8 & E.3.
SO_2	Gas	8,760		2.5	101.6**			OGC Case#91-1610	C.9 & E.3.
SO_2	Oil	8,760	0.80 lb/MMBtu		101.6**			OGC Case#91-1610	C.9. & E.3.
NO_X	Gas	8,760		104.35	622.0**			OGC Case#91-1610	C 10. & E.3
VOC	Gas	8,760		0 266	2.3**			OGC Case#91-1610	C.11. & E.3.
CO	Gas	8,760		7 589	45.3**			OGC Case#91-1610	C.12. & E.3.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.
** The total combined emissions from EU [-004], [-007], and [-008]

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Table 1-1, Summary of Air Pollutant Standards and Terms

Ft. Pierce Utilities Authority
H. D. King Power Plant

FINAL Title V Permit Renewal No.: 1110003-005-AV
Facility ID No.: 1110003

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No.	Brief Description
[-008]	56.1 MW Boiler - Unit #8

			Allowable Emissions			Equivalent Emissions*			
Pollutant Name	Fuel(s)	Hours/Year	Standard(s)	lbs./hour	TPY	lbs./hour	TPY	Regulatory Citation(s)	See permit condition(s)
VE	Gas	8,760	Not Exceed 5%					OGC Case#91-1610	D.5.
VE	Oil	8,760	20% except 27% 6 min/hr					OGC Case#91-1610	D.5.
VE	All	8,760	60% 3 hrs/24 hrs					62-210.700(3), FAC	D.6.
PM	Gas	8,760		0.945	16.0**			OGC Case#91-1610	D.7. & E.3.
PM	Oil		0.1 lb/MMBtu		16.0**			OGC Case#91-1610	D.7. & E.3.
PM	Oil		0.3 lb/MMBtu 3hrs/24 hrs		16.0**			62-210.700(3), FAC	D 8. & E.3.
SO_2	Gas	8,760		2 5	101.6**			OGC Case#91-1610	D.9. & E.3.
SO_2	Oil	8,760	0.80 lb/MMBtu		101.6**			OGC Case#91-1610	D.9. & E.3.
NO_X	Gas	8,760	0 20 lb/MMBtu		622.0**			OGC Case#91-1610 & 40 CFR 60.44(a)(1)	D.10. & E.3.
NO_X	Oil	8,760	0.30 lb/MMBtu		622.0**			OGC Case#91-1610 & 40 CFR 60.44(a)(2)	D.10. & E.3.
VOC	Gas	8,760		0.441	2.3**			OGC Case#91-1610	D 11. & E.3.
CO	Gas	8,760		12.59	45.3**			OGC Case#91-1610	D.12. & E.3.

Notes:
* The "Equivalent Emissions" listed are for informational purposes only.
** The total combined emissions from EU [-004], [-007], and [-008]

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Table 2-1, Summary of Compliance Requirements

Ft. Pierce Utilities Authority
H. D. King Power Plant

FINAL Title V Permit Renewal No.: 1110003-005-AV
Facility ID No.: 1110003

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No.	**Brief Description**
[-003]	23.4 MW Combined Cycle Gas Turbine with 8.2 MW HRSG - Unit #9

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS**	See permit condition(s)
NO_x	All	EPA Method 20	Annual	9/30/1990	1 hr	Yes	A.14., A.18, A.19., & A.22.
SO_2	All	EPA Method 20	Annual	9/30/1990	1 hr		A.14., A.18, A.19., & A.22.
SO_2	Oil	Fuel Analysis		9/30/1990			A.21.
VE	All	EPA Method 9	Annual	9/30/1990	60 min		A.23.
CO	All	EPA Method 10	Annual	9/30/1990	1 hr		A.24.

Notes:
* The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

[electronic file name: 11100032.xls]

Table 2-1, Summary of Compliance Requirements

Ft. Pierce Utilities Authority
H. D. King Power Plant

FINAL Title V Permit Renewal No.: 1110003-005-AV
Facility ID No.: 1110003

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No.	**Brief Description**
[-004]	16.5 MW Boiler - Unit #6

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS**	See permit condition(s)
VE	Gas	EPA Method 9	Annual	6/24/1983	30 min		B.17. & B.31.
VE	Oil	DEP Method 9	Annual	6/24/1983	60 min		B.17. & B.18.
PM	All	EPA Method 5	Renewal	6/24/1983	60 min		B.18., B.30. & B.32.
SO_2	All	EPA Method 6 or 6C or Fuel Analysis	Annual	6/24/1983	60 min		B.20., B.21. & B.30.
NO_X	Gas	EPA Method 7 or 7E	Annual	6/24/1983	60 min		B.22. & B.30.
VOC	Gas	EPA Method 25A	Renewal	6/24/1983	60 min		B.23. & B.30.
CO	Gas	EPA Method 10	Renewal	6/24/1983	60 min		B.24. & B.30.

Notes:
* The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

[electronic file name: 11100032.xls]

Table 2-1, Summary of Compliance Requirements

Ft. Pierce Utilities Authority
H. D. King Power Plant

FINAL Title V Permit Renewal No.: 1110003-005-AV
Facility ID No.: 1110003

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No.	Brief Description
[-007]	37.5 MW Boiler - Unit #7

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date *	Min. Compliance Test Duration	CMS**	See permit condition(s)
VE	Gas	EPA Method 9	Annual	9/30/1991	30 min		C.17. & C.31.
VE	Oil	DEP Method 9	Annual	9/30/1991	60 min		C.17. & C.18.
PM	All	EPA Method 5	Renewal	9/30/1991	60 min		C.19., C.30. & C.32.
SO_2	All	EPA Method 6 or 6C or Fuel Analysis	Annual	9/30/1991	60 min		C.20., C.21. & C.30.
NO_X	Gas	EPA Method 7 or 7E	Annual	9/30/1991	60 min		C.22. & C.30.
VOC	Gas	EPA Method 25A	Renewal	9/30/1991	60 min		C.23. & C.30.
CO	Gas	EPA Method 10	Renewal	9/30/1991	60 min		C.24. & C.30.

Notes:
* The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

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Table 2-1, Summary of Compliance Requirements

Ft. Pierce Utilities Authority
H. D. King Power Plant

FINAL Title V Permit Renewal No.: 1110003-005-AV
Facility ID No.: 1110003

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID No.	Brief Description
[-008]	56.1 MW Boiler - Unit #8

Pollutant Name or Parameter	Fuel(s)	Compliance Method	Testing Time Frequency	Frequency Base Date*	Min. Compliance Test Duration	CMS**	See permit condition(s)
VE	Gas	EPA Method 9	Annual	9/30/1991	30 min		D.18.. & D.34.
VE	Oil	DEP Method 9	Annual	9/30/1991	60 min		D.18.. & D.19.
PM	All	EPA Method 5	Renewal	9/30/1991	60 min		D.20., D.33. & D.35.
SO_2	All	EPA Method 6 or 6C or Fuel Analysis	Annual	9/30/1991	60 min		D.21., D.22. & D.33.
NO_X	Gas	EPA Method 7 or 7E	Annual	9/30/1991	60 min	Yes	D.23. & D.33.
VOC	Gas	EPA Method 25A	Renewal	9/30/1991	60 min		D.24. & D.33.
CO	Gas	EPA Method 10	Renewal	9/30/1991	60 min		D.25. & D.33.

Notes:
* The frequency base date is established for planning purposes only; see Rule 62-297.310, F.A.C.
**CMS [=] continuous monitoring system

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ATTACHMENT FPU-EU1-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT FPU-EU1-IV3

ALTERNATIVE METHODS OF OPERATION
UNIT 9

Combined-cycle gas turbine Unit No. 9 is fired with natural gas as a primary fuel. No. 2 fuel oil is used as a backup fuel.

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 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 for air permit. 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 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/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. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** 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 construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:

   37.5 MW Boiler - Unit #7

3. Emissions Unit Identification Number: **007**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A		**1/5/64**	**49**	☒ Yes ☐ No

9. Package Unit:
   Manufacturer: **Brown Boveri** Model Number: **DSQ2g44**

10. Generator Nameplate Rating: **37.5** MW

11. Emissions Unit Comment:

    Emission unit is a 37.5-MW natural gas-fired steam electric generator. No. 2 fuel oil is used as backup.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Multiple cyclone for PM control.**
2. Control Device or Method Code(s): **76**

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: 470 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 based on natural gas or No. 2 fuel oil firing. Natural gas is used as primary fuel with No. 2 fuel oil used as backup. Combined annual heat input from EUs 004 (16.5 MW Boiler - Unit #6), 007 (37.5 MW Boiler Unit #7), and 008 (56.1 MW Boiler - Unit #8) limited to 4,534,930 MMBtu/yr. Combined annual fuel oil usage from EUs 004 (16.5 MW Boiler - Unit #6), 007 (37.5 MW Boiler Unit #7), and 008 (56.1 MW Boiler - Unit #8) limited to 400 hrs/yr.	

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: **No. 7 Boiler**		2. Emission Point Type Code: **1**
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: **004**		
5. Discharge Type Code: **V**	6. Stack Height: **147** feet	7. Exit Diameter: **7.1** feet
8. Exit Temperature: **308** °F	9. Actual Volumetric Flow Rate: **145,081** acfm	10. Water Vapor: **13.73** %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **566.8** North (km): **3,036.3**		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) **27/27/00** Longitude (DD/MM/SS) **80/19/26**
15. Emission Point Comment: **Exit temperature and exhaust flow rates are from Title V permit application dated July 2002.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

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 natural gas burned**	
4. Maximum Hourly Rate: **0.455**	5. Maximum Annual Rate: **3,986**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,033**
10. Segment Comment: **Maximum hourly rate = 470 MMBtu/hr /1033 MMBtu/MM ft^3 = 0.455 MM ft^3/hr** **Maximum annual rate = 470 MMBtu/hr /1033 MMBtu/MM ft^3 x 8,760 hrs/yr = 3,985.7 MM ft^3/hr** **Combined annual heat input from Boiler Unit #6, Boiler Unit #7, and Boiler Unit #8 limited to 4,534,930 MMBtu/yr.**		

Segment Description and Rate: Segment 2 of 2

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: **3.406**	5. Maximum Annual Rate: **1362**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Maximum hourly rate = 470 MMBtu/hr /138 MMBtu/1,000 gallon = 3,405.8 gallons/hr.** **Maximum annual rate = 3405.8 gallons/hr x 400 hr/yr = 1,362.3x10^3 gallons/yr.** **Combined annual fuel oil usage from EUs 004 (16.5 MW Boiler - Unit #6), 007 (37.5 MW Boiler Unit #7), and 008 (56.1 MW Boiler - Unit #8) limited to 400 hrs/yr.**		

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
PM	76		EL
PM_{10}	76		NS
CO			EL
VOC			EL
SO_2			EL
NO_x			EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **141.0** lb/hour **16** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.3 lb/MMBtu** Reference: **62-210.700(3), F.A.C.**	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: **Hourly emissions = 0.3 lb/MMBtu x 470 MMBtu/hr = 141.0 lb/hr (Oil firing, soot blowing scenario)**	
11. Potential Fugitive and Actual Emissions Comment: **Hourly emissions based on soot blowing while oil firing.** **Annual emissions limited to 16 TPY per Permit No. 1050003-013-AV.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **0.568 lb/hr**	4. Equivalent Allowable Emissions: **0.568** lb/hour **2.49** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing.** **Permit No. 1110003-005-AV.** **Annual compliance test not required if firing only natural gas or if oil firing for <400 hr/yr.**	

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: **0.3 lb/MMBtu**	4. Equivalent Allowable Emissions: **141.0** lb/hour **16** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on oil firing during soot blowing operations.** **Rule 62-210.700(3), F.A.C. and Permit No. 1110003-005-AV.** **Annual emissions limited to 16 TPY. (OGC Case No. 91-1610).** **Compliance test required if oil firing >400 hr/yr.**	

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: **16 TPY**	4. Equivalent Allowable Emissions: lb/hour **16** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **Combined emissions from Boiler Unit Nos. 6, 7, and 8 limited to 16 TPY.** **OGC Case No. 91-1610.**	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 376.0 lb/hour 85.7 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: 0.8 lb/MMBtu Reference: Permit No. 1050003-013-AV / AC56-141460A / OGC Case No. 91-1610	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:

Hourly emissions = 0.8 lb/MMBtu x 470 MMBtu/hr = 376.0 lb/hr (Oil firing)

Annual emissions = (0.8 lb/MMBtu x 470 MMBtu/hr x 400 hrs/yr) + (2.5 lb/hr x 8,360 hrs/yr) x 1 TPY/2,000 lbs = 85.65 TPY

11. Potential Fugitive and Actual Emissions Comment:

Hourly emissions based on oil firing.

Annual emissions based on 400 hours of oil firing and 8,360 hrs/yr of natural gas-firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **2.5 lb/hr**	4. Equivalent Allowable Emissions: **2.5** lb/hour **11.0** tons/year
5. Method of Compliance: **EPA Method 6 or 6C or fuel analysis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing. Permit No. 1110003-005-AV / AC56-141460A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.8 lb/MMBtu**	4. Equivalent Allowable Emissions: **376.0** lb/hour **75.2** tons/year
5. Method of Compliance: **EPA Method 6 or 6C or fuel analysis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on oil firing. Permit No. 1110003-005-AV / AC56-141460A. Annual emissions based on oil firing for 400 hrs/yr.**	

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: **101.6 TPY**	4. Equivalent Allowable Emissions: lb/hour **101.6** tons/year
5. Method of Compliance: **EPA Method 6 or 6C or fuel analysis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Combined annual emissions of Boiler Unit Nos. 6, 7, and 8 limited to 101.6 TPY. OGC Case No. 91-1610.**	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **104.35** lb/hour **457.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **104.35 lb/hr** Reference: **Permit No. 1110003-005-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: **Annual emissions = 104.35 lb/hr x 8,760 hrs/yr x 1 TPY/2,000 lbs = 457.1 TPY**	
11. Potential Fugitive and Actual Emissions Comment: **Hourly emissions limited to 104.35 lb/hr when firing natural gas.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **104.35 lb/hr**	4. Equivalent Allowable Emissions: **104.35** lb/hour **457.1** tons/year
5. Method of Compliance: **EPA Method 7 or 7E.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing. Permit No. 1110003-005-AV / OGC Case No. 91-1610.**	

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: **622 TPY**	4. Equivalent Allowable Emissions: lb/hour **622** tons/year
5. Method of Compliance: **EPA Method 7 or 7E.**	
6. Allowable Emissions Comment (Description of Operating Method): **Total combined emissions of Boiler Unit Nos. 6, 7, and 8 limited to 622 TPY. OGC Case No. 91-1610.**	

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/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17.01** lb/hour **35.12** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5 lb/1000 gallons** Reference: **Table 1.3-1, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Emission factor = 5 lb/1000 gallons x 1000 gallons/138 MMBtu = 0.0362 lb/MMBtu
Hourly emissions = 0.0362 lb/MMBtu x 470 MMBtu/hr = 17.01 lb/hr
Annual emissions = (0.0362 lb/MMBtu x 470 MMBtu/hr x 400 hrs/yr) + (7.589 lb/hr x 8,360 hrs/yr) x 1 TPY/2,000 lbs = 35.12 TPY

11. Potential Fugitive and Actual Emissions Comment:

Hourly emissions based on oil firing.

Annual emissions based on 400 hours of oil firing and 8,360 hrs/yr of natural gas-firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **7.589 lb/hr**	4. Equivalent Allowable Emissions: **7.589** lb/hour **33.24** tons/year
5. Method of Compliance: **EPA Method 10.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing. Permit No. 1110003-005-AV / OGC Case No. 91-1610.**	

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: **45.3 TPY**	4. Equivalent Allowable Emissions: lb/hour **45.3** tons/year
5. Method of Compliance: **EPA Method 10.**	
6. Allowable Emissions Comment (Description of Operating Method): **Total combined emissions of Boiler Unit Nos. 6, 7, and 8 limited to 45.3 TPY. OGC Case No. 91-1610.**	

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/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.682** lb/hour **1.25** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.2 lb/1000 gallons** Reference: **Table 1.3-3, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Emission factor = 0.2 lb/1000 gallons x 1000 gallons/138 MMBtu = 0.00145 lb/MMBtu
Hourly emissions = 0.00145 lb/MMBtu x 470 MMBtu/hr = 0.682 lb/hr
Annual emissions = (0.00145 lb/MMBtu x 470 MMBtu/hr x 400 hrs/yr) + (0.266 lb/hr x 8,360 hrs/yr) x 1 TPY/2,000 lbs = 1.25 TPY

11. Potential Fugitive and Actual Emissions Comment:
Hourly emissions based on oil firing.

Annual emissions based on 400 hours of oil firing and 8,360 hrs/yr of natural gas-firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **0.266 lb/hr**	4. Equivalent Allowable Emissions: **0.266** lb/hour **1.17** tons/year
5. Method of Compliance: **EPA Method 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing. Permit No. 1110003-005-AV / OGC Case No. 91-1610.**	

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: **2.3 TPY**	4. Equivalent Allowable Emissions: lb/hour **2.3** tons/year
5. Method of Compliance: **EPA Method 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Total combined emissions of Boiler Unit Nos. 6, 7 and 8 limited to 2.3 TPY. OGC Case No. 91-1610.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype: **VE5**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **5** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE test using EPA Method 9**	
5. Visible Emissions Comment: **Visible emissions limited to 5 percent opacity when firing natural gas. Permit No. 1110003-005-AV.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **40** % Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **DEP Method 9**	
5. Visible Emissions Comment: **Visible emissions limited to 20 percent opacity when firing fuel oil. Permit No. 1110003-005-AV.**	

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: **VE60**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **60** % Exceptional Conditions: **>60** % Maximum Period of Excess Opacity Allowed: **4 periods of 6** min/hour	
4. Method of Compliance: **VE test using EPA Method 9**	
5. Visible Emissions Comment: **Rule 62-210.700(3), F.A.C. and Permit No. 1050003-013-AV.** **60 percent opacity during load changing and boiler cleaning (soot blowing) for 3 hours in any 24 hour period.** **Annual VE test required if >400 hrs/yr oil operation.**	

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: ☐ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
5. Visible Emissions Comment:	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number: 132	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement: ☐ Rule Other	
4. Monitor Information... Manufacturer: Model Number: Serial Number:	
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

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: **FPU-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: **FPU-EU1-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: **FPU-EU2-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: **FPU-EU2-I4** ☐ Previously Submitted, Date _____ ☐ 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: **August 22, 2006** ☐ To be Submitted, Date (if known): _____ Test Date(s)/Pollutant(s) Tested: _____ ☐ Not Applicable Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7.	Other Information Required by Rule or Statute ☐ Attached, Document ID: _____ ☒ Not Applicable

EMISSIONS UNIT INFORMATION
Section [2]
37.5 MW Boiler - Unit #7

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 (Rule 62-212.400(4)(d), F.A.C., and Rule 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	

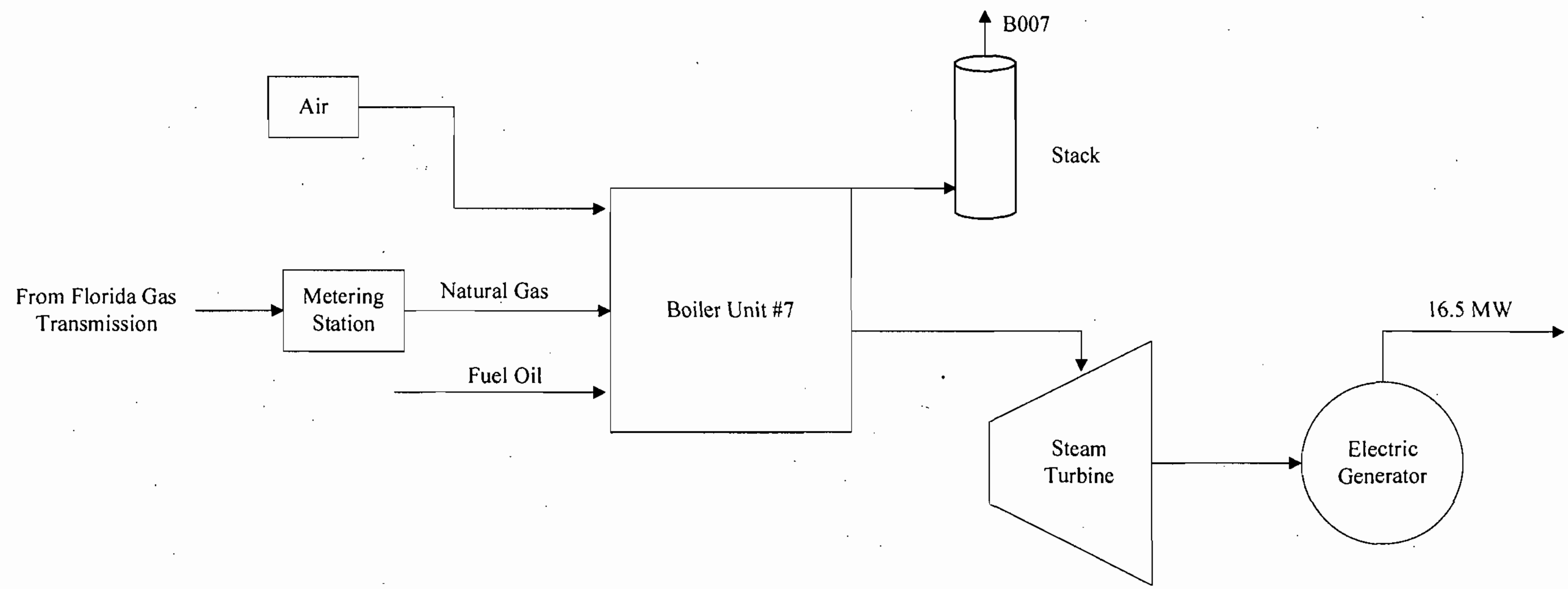
Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☒ Attached, Document ID: **FPU-EU1-IV1** ☐ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _____ ☒ Not Applicable	
3. Alternative Methods of Operation ☒ Attached, Document ID: **FPU-EU2-IV3** ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☒ Previously Submitted, Date: **August 28, 2002** ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Not Applicable	

Additional Requirements Comment

ATTACHMENT FPU-EU2-I1

PROCESS FLOW DIAGRAM



Attachment FPU-EU2-I1
37.5 MW Boiler Unit #7
Process Flow Diagram
Fort Pierce Utilities - H.D. King Power Plant
Fort Pierce, Florida

Process Flow Legend
Solid/Liquid
Gas
Steam

Filename: 07387523/PROCESS FLOW DIAGRAMS.VSD
Date: 06/18/07

Golder Associates

ATTACHMENT FPU-EU2-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

BEST AVAILABLE COPY

AEROTEC INDUSTRIES, INC.

UNIT #7
CYCLONES

JOB SUMMARY

Foster Wheeler Corporation
P. O. No. N-1581-2-78-234
City of Fort Pierce, Florida
Aerotec Industries, Inc. File No. 60-488

(2) Design 6UMIT #16-367 Aerotec Coll's, water washing system in inlet and outlet areas.

PERFORMANCE: Elev.: Sea Level		Bar.: 30"Hg.
Lbs. Gas per Hour	248,000	269,000
Temperature Deg. F.	311	311
CFM at Pressure	77,100	83,900
Collector Resistance "W.G.	2.50	2.96
Collection Efficience, %	91	

The above noted collection efficiency is guaranteed in accordance with curve GO-31-E-R1 and the following Flys Ash Analysis.

DUST ANALYSIS
ELUTRIATION

Particle Size	Average Fartical Size	% In Gas Stream
/60 Microns	60 Microns	16
-60/40 Microns	50 Microns	3
-40/30 Microns	35 Microns	4
-30/20 Microns	25 Microns	14
-20/15 Microns	17.5 Microns	11
-15/10 Microns	12.5 Microns	17
-10/ 7 1/2 Microns	8.75 Microns	10
- 7-1/2 Microns	3.75 Microns	25

AT/cf
9/26/61

CYCLONES

PRAT-DANIEL CORPORATION

POWER PLANT EQUIPMENT

Executive Offices and Plant
South Norwalk, Conn.

Fans, Stacks
Dust Collectors
Air Heaters
Thermobloc
Industrial Heaters

Project & Sales Engineers
THE THERMIX CORPORATION
Greenwich, Connecticut

JOB SUMMARY

The Babcock & Wilcox Company
P. O. #777-232523 Gr. 89
City of Fort Pierce, Fla.
Prat-Daniel File 357-55

(1) Design 6UPHT #18-386 Prat-Daniel Tubular Dust Collector, 3/16" Corten steel hoppers, inlet damper, water washing system

PERFORMANCE: Elev. Sea Level Bar.: 30" Hg.

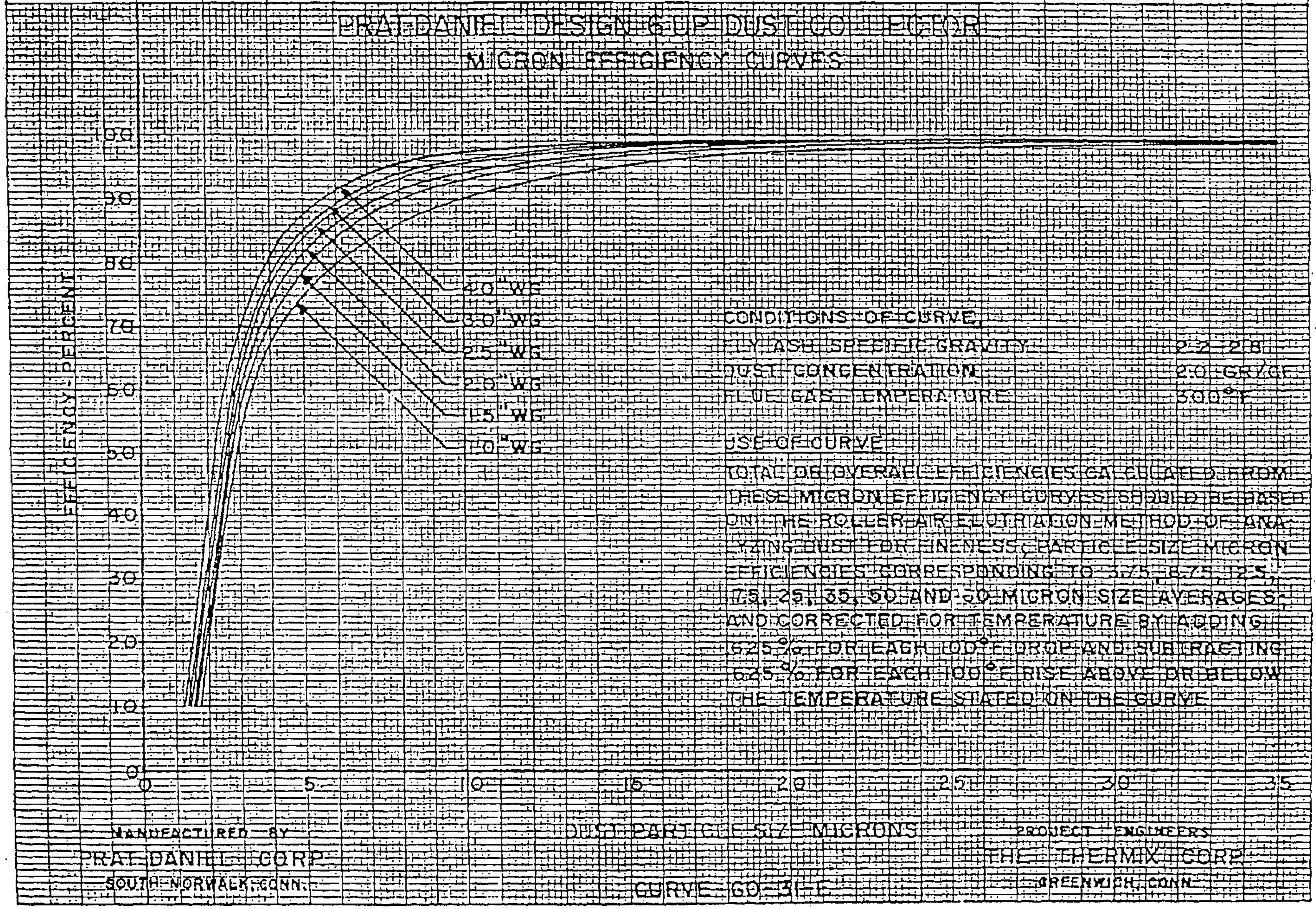
Lbs. gas per hour	242,000
Temperature deg. F.	350
Collector resistance, "w.g.	2.5

Collection efficiency based on Curve CO-31-E.

MM:MMT
5/15/56

THERMIX	NAME	DATE
DRAWN BY	aea	5/19/55
COMPUTED BY		

APPROVED BY	NAME	DATE
THERMIX	[illegible]	5/19/55
PRAT-DANIEL		



FORM: PDC 4513

ATTACHMENT FPU-EU2-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

NO. 7 BOILER PRELIGHT CHECKLIST

PURPOSE

This procedure has been prepared to serve as a guide to ensure that all systems and related equipment pertaining to the prelight of a steam generator is properly inspected and determined that it is fully functional prior to putting equipment into service.

SCOPE

As a safety precaution, responsibilities are listed in checklist form to ensure proper inspection of boilers by the Operators and acknowledged by the Watch Engineer. This does not necessarily dictate the order in which equipment is checked out, nor is it all inclusive and should not be relied on as a substitute for good operating practice based on individual experience and training.

POLICY

The checklist will be preformed and checked off before attempting to place equipment/prelight of steam generators into service.

GENERAL

The Boiler Prelight Checklist for the prospective unit will be properly filled out by both Operator and the Watch Engineer and then turned in to the Plant Operations Supervisor.

PREPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.:
Stephen Tudor, Jr.	HP	POWER PLANT	2-12-92	0

NO. 7 BOILER PRELIGHT CHECKLIST

OPER	1.	DRUM LEVEL IS UP TO FIRING LEVEL (1 BUBBLE IN SIGHTGLASS.)	☐
OPER	2.	CHECK ALARM PANELS IN BOILER ROOM AND TURBINE PANEL, TEST ALARMS, REPLACE BULBS AS NECESSARY. PLACE MOLYTEKS IN AUTO MODE (BOILER ROOM AND TURBINE BOARD.)	☐
OPER	3.	CHECK FOR TAGS ON EQUIPMENT IN BOILER ROOM, AT TURBINE PANEL AND IN 2400 SWITCHGEAR ROOM. NOTIFY WATCH ENGINEER OF ANY TAGS ON ANY EQUIPMENT.	☐
OPER	4.	REMOVE NITROGEN BLANKET OFF BOILER, CLOSE VALVE AT BOILER VENT AND SHUT FLOW OFF AT SCAVENGER.	☐
OPER	5.	OPEN BOILER VENTS (3)- SUPERHEATER, SPRAY HEADER, AND NORTH DRUM VENTS.	☐
OPER	6.	OPEN BOILER DRAINS (3)- MAIN, BEFORE AND AFTER SPRAY-HEADER DRAINS; UPSTREAM AND DOWNSTREAM VALVES.	☐
OPER	7.	VALVES BEFORE AND AFTER ATTEMPERATOR CONTROL REG. ARE OPEN (BYPASS CLOSED) AND UPSTREAM VALVE OPEN.	☐
OPER	8.	VALVES BEFORE AND AFTER FEEDWATER REGULATOR ARE OPEN, AND FEEDWATER REGULATOR IS IN AUTO POSITION AT REGULATOR.	☐
OPER	9.	CHECK POSITION OF FEEDWATER STOP VALVE AT DRUM.	☐
OPER	10.	INSPECT ALL BOILER ENTRANCE DOORS TO MAKE SURE THEY ARE SECURE, AND NO WATER APPEARS FROM BOILER DRUM HATCHES.	☐
OPER	11.	NORTH AND SOUTH BOILER BLOWDOWN VALVES SHOULD BE CLOSED. BLOWDOWNS SHOULD BE LINED UP TO FLASH TANK.	☐
OPER	12.	NORTH AND SOUTH SIDE WATERWALL HEADER DRAINS SHOULD BE CLOSED.	☐

PREPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.:
...Tudor, Jr.	JR	POWER PLANT	2-12-92	0

NO. 7 BOILER PRELIGHT CHECKLIST (CON'T.)

OPER	13.	CHECK OUT FEEDWATER PUMPS: (A) COOLING WATER TO PUMP; (B) WATER ON TO GLANDS (C) SUCTION VALVES OPEN; (D) DISCHARGE VALVES CLOSED UNTIL PUMP IS STARTED ; (E) VENTS OPEN ; (F) CHECK OIL LEVELS AT MOTORS AND RESERVOIRS ;(G) RECIRC. VALVES AT DA OPEN AND MANUAL RECIRC. SWITCH IN BOILER ROOM IS IN MANUAL POSITION ;(H) ALL RELATED PIPING AND VALVES.	☐
OPER	14.	CHECK OUT FORCED DRAFT FANS, OIL LEVELS, REGATRONS, AND BREAKERS; AND MAKE SURE BRUSHES ARE INSTALLED.	☐
OPER	15.	OPEN WINDBOX, BOILER EXIT, AND CROSSARM DAMPERS ON FORCED DRAFT FAN TO BE PLACED IN SERVICE. MAKE SURE STACK DAMPERS ARE OPEN ON NORTH AND SOUTH SIDES. ALSO CHECK THE LOW VOLTAGE LOCKOUT RELAY IN 2400 V ROOM TO MAKE SURE IT IS NOT TRIPPED OUT.	☐
OPER	16.	CHECK OIL LEVELS OF AIRHEATER TRUNION BEARINGS AND AIR HEATER MOTOR DRIVE.	☐
PER	17.	CHECK COOLING WATER TO AIRHEATER BEARINGS.	☐
OPER	18.	TURN ON 02 ANALYZER AND CHECK CALIBRATION.	☐
OPER	19.	CHECK LOCAL CONTROL PANELS AT EACH BURNER FOR AIR REGISTER OPERATION, IGNITORS IN AUTO POSITION, GUILLOTINES ARE CLOSED AND CHECK COOLING AIR VALVES. MAKE SURE BURNERS ARE IN THE GAS POSITION (IN) AND CHECK FIRE EYES FOR DIRT AND/OR WATER.	☐
OPER	20.	CHECK FORNEY BURNER CABINETS FOR TAGS AND INFORM WATCH ENGINEER	☐
OPER	21.	INSPECT ALL COOLING AIR LINES AND VALVES AT PORTHOLES.	☐
OPER	22.	HOUSE AIR COMPRESSOR IS ON AND THE OTHER IS ON STANDBY.	☐
OPER	23.	MAKEUP PUMP IS LINED TO D.A. AND CHECK D.A. LEVEL.	☐

EPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.:
Tudor, Jr.	TP	POWER PLANT	2-12-92	0

BEST AVAILABLE COPY

NO. 7 BOILER PRELIGHT CHECKLIST (CON'T,)

OPER	24.	MAKE SURE WE HAVE FULL INSTRUMENT AIR PRESSURE. CHECK ALL VALVES AT FILTERS (30 PSI.)	☐
OPER	25.	CHECK DAY TANK LEVELS, AND BE SURE TO AND FROM SYSTEM VALVE IS OPEN AT DAY TANK.	☐
OPER	26.	CHECK YARD GAS VALVES, OPEN S-4 VALVE AT GAS HEADER ON PLATFORM. MAKE SURE MINIMUM FLOW VALVE IS FULLY OPEN, AND THE MAIN GAS VALVE BEFORE MAIN REDUCER IS CLOSED (UNTIL WE ARE ON THE LINE.)	☐
OPER	27.	CHECK IGNITOR GAS SUPPLY (CITY OR FLORIDA GAS.)	☐
OPER	28.	MAIN STEAM STOP VALVE OPEN (UNLESS OTHERWISE INSTRUCTED BY THE WATCH ENGINEER.)	☐
OPER	29.	INFORM CONTROL ROOM BEFORE STARTING FD FAN.	☐
OPER	30.	START FAN AND INITIATE PURGE, CHECK FAN FOR VIBRATION AND BRUSHES FOR ARCING. ALSO, CHECK OIL SLINGERS.	☐
OPER	31.	BE PREPARED TO PUT FIRE IN BOILER AND BRING BOILER UP AS USUAL.	☐
ENGR.	32.	NOTIFY FLORIDA GAS THAT UNIT WILL BE COMING ON THE LINE.	☐
ENGR.	33.	MAKE SURE ALL PERMITS ARE REVIEWED AND CLOSED IF NECESSARY PRIOR TO PLACING UNIT IN SERVICE.	☐
OPER	34.	CHECK PALOMETER	☐

PREPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.:
Tinker Tudor, Jr.	HP	POWER PLANT	2-12-92	0

#7 UNIT SHUTDOWN PROCEDURE

1 Boiler room lowers boiler pressure 50 to 100 psi. (from 900 to 800 psi)

2 Control room lowers generator to about 3 megawatts and switches station service from T-17 to T-18.

3 Boiler room takes gas fire out of boiler and starts a boiler purge and tells control room to take unit off line..

4 Control room operator lowers the generator voltage down from 13.8KV to 13.5KV

5 Control room lowers generator down to zero MW. When the generator watthour meter stops turning the operator opens the generator breaker and the field breaker.

6 When generator is off line control room operator informs the shift supervisor and he/she will close the throttle valve stopping the turbine.

7 Auxiliary operator controls condenser/hotwell and deaerating heater (DA) levels until the DA temperature is below 212 degrees and then pertaining auxiliary equipment is shutdown.

8 Shift supervisor places turbine-generator on turning gear once the turbine rolls down to zero speed.

9 Once the boiler has completed its 5 min. purge the FD fan is shut down and all gas valves are closed pertaining to the unit.

ATTACHMENT FPU-EU2-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT FPU-EU2-IV3

ALTERNATIVE METHODS OF OPERATION

UNIT 7

Fossil fuel-fired steam generator Unit No. 7 is fired with natural gas as a primary fuel. No. 2 fuel oil is fired as a secondary/emergency fuel. Fuel oil firing in Boiler Unit Nos. 6, 7, and 8 is limited to a combined total of 400 hours per year.

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 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 for air permit. 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 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/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. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** 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 construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

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

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

Emissions Unit Description and Status

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

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

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

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

2. Description of Emissions Unit Addressed in this Section:

   56.1 MW Boiler - Unit #8

3. Emissions Unit Identification Number: **008**

4. Emissions Unit Status Code:	5. Commence Construction Date:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A		**1/4/76**	**49**	☒ Yes ☐ No

9. Package Unit:
   Manufacturer: **General Motors Corp.** Model Number: **MP-45**

10. Generator Nameplate Rating: **56.1** MW

11. Emissions Unit Comment:

   Emission unit is a 56.1-MW natural gas-fired steam electric generator. No. 2 fuel oil is used as backup.

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description:
2. Control Device or Method Code(s):

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: 644 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 based on natural gas or fuel oil firing.** **Natural gas is used as primary fuel with No. 2 fuel oil used as backup.** **Combined annual heat input from EUs 004 (16.5 MW Boiler - Unit #6), 007 (37.5 MW Boiler Unit #7), and 008 (56.1 MW Boiler - Unit #8) limited to 4,534,930 MMBtu/yr.** **Combined annual fuel oil usage from EUs 004 (16.5 MW Boiler - Unit #6), 007 (37.5 MW Boiler Unit #7), and 008 (56.1 MW Boiler - Unit #8) limited to 400 hrs/yr.**	

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: **No. 8 Boiler**		2. Emission Point Type Code: **1**
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: **008**		
5. Discharge Type Code: **V**	6. Stack Height: **150** feet	7. Exit Diameter: **8.0** feet
8. Exit Temperature: **334** °F	9. Actual Volumetric Flow Rate: **252,011** acfm	10. Water Vapor: **15.66** %
11. Maximum Dry Standard Flow Rate: dscfm		12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **566.8** North (km): **3,036.3**		14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) **27/27/00** Longitude (DD/MM/SS) **80/19/26**
15. Emission Point Comment: **Exit temperature and exhaust flow rate are from Title V permit application dated July 2002.**		

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

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 natural gas burned**	
4. Maximum Hourly Rate: **0.623**	5. Maximum Annual Rate: **4,390**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,033**
10. Segment Comment: **Maximum hourly rate = 644 MMBtu/hr /1033 MMBtu/MM ft^3 = 0.623 MM ft^3/hr** **Maximum annual rate = 4,534,930 MMBtu/yr / 1,033 MMBtu/MM ft^3 = 4,390 MM ft^3/yr** **Combined annual heat input from Boiler Unit Nos. 6, 7, and 8 limited to 4,534,930 MMBtu/yr.**		

Segment Description and Rate: Segment 2 of 2

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: **4.667**	5. Maximum Annual Rate: **1867**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Maximum hourly rate = 644 MMBtu/hr /138 MMBtu/1,000 gallon = 4,666.7 gallons/hr.** **Maximum annual rate = 4666.7 gallons/hr x 400 hr/yr = 1,866.7x10^3 gallons/yr.** **Combined annual fuel oil usage from EUs 004 (16.5 MW Boiler - Unit #6), 007 (37.5 MW Boiler Unit #7), and 008 (56.1 MW Boiler - Unit #8) limited to 400 hrs/yr.**		

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
PM	76		EL
PM_{10}	76		NS
CO			EL
VOC			EL
SO_2			EL
NO_x			EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **193.2** lb/hour **16** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.3 lb/MMBtu** Reference: **62-210.700 (3), F.A.C.**	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:
Hourly emissions = 0.3 lb/MMBtu x 644 MMBtu/hr = 193.2 lb/hr (Oil firing, soot blowing scenario)

11. Potential Fugitive and Actual Emissions Comment:
Hourly emissions based on soot blowing while oil firing.

Annual emissions based on 16 tons/yr, aggregate limit for all boilers. .

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **0.945 lb/hr**	4. Equivalent Allowable Emissions: **0.945** lb/hour **4.14** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing.** **Permit No. 1110003-005-AV.** **Annual compliance test not required if firing only natural gas or if oil firing for <400 hr/yr.**	

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: **0.3 lb/MMBtu**	4. Equivalent Allowable Emissions: **193.2** lb/hour **16** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on oil firing during soot blowing operations.** **Rule 62-210.700(3), F.A.C. and Permit No. 1110003-005-AV.** **Annual emissions limited to 16 TPY (OGC Case No. 91-1610).** **Compliance test required if oil firing >400 hr/yr.**	

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: **16 TPY**	4. Equivalent Allowable Emissions: lb/hour **16** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **Combined emissions from Boiler Unit Nos. 6, 7, and 8 limited to 16 TPY.** **OGC Case No. 91-1610.**	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 515.2 lb/hour 101.6 tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: 0.8 lb/MMBtu Reference: Permit No. 1050003-013-AV / AC 56-141460A / OGC Case No. 91-1610	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: Hourly emissions = 0.8 lb/MMBtu x 644 MMBtu/hr = 515.2 lb/hr (Oil firing)	
11. Potential Fugitive and Actual Emissions Comment: Hourly emissions based on oil firing. Combined annual emissions from Boiler Unit Nos. 6, 7, and 8 limited to 101.6 TPY. (OGC Case No. 91-1610).	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **2.5 lb/hr**	4. Equivalent Allowable Emissions: **2.5** lb/hour **11.0** tons/year
5. Method of Compliance: **EPA Method 6 or 6C or fuel analysis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing.** **Permit No. 1110003-005-AV / AC56-141460A / OGC Case No. 91-1610.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.8 lb/MMBtu**	4. Equivalent Allowable Emissions: **515.2** lb/hour **101.6** tons/year
5. Method of Compliance: **EPA Method 6 or 6C or fuel analysis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on oil firing.** **Permit No. 1110003-005-AV / AC56-141460A / OGC Case No. 91-1610.** **Annual emissions based on an aggregate limit of 101.6 TPY.**	

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: **101.6 TPY**	4. Equivalent Allowable Emissions: lb/hour **101.6** tons/year
5. Method of Compliance: **EPA Method 6 or 6C or fuel analysis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Combined annual emissions of Boiler Unit Nos. 6, 7, and 8 limited to 101.6 TPY.** **OGC Case No. 91-1610.**	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **193.2** lb/hour **577.0** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.3 lb/MMBtu** Reference: **40 CFR 60.44 (a) (1) and (2)**	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: **Hourly emissions = 0.3 lb/MMBtu x 644 MMBtu/hr = 193.2 lb/hr (Oil firing)** **Annual emissions = (0.3 lb/MMBtu x 644 MMBtu/hr x 400 hrs/yr) + (0.2 lb/MMBtu x 644 MMBtu/hr x 8,360 hrs/yr) x 1 TPY/2,000 lbs = 577.02 TPY**	
11. Potential Fugitive and Actual Emissions Comment: **Hourly emissions based on fuel oil firing.** **Annual emissions based on 400 hours of oil firing and 8,360 hrs/yr of natural gas-firing.**	

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **0.2 lb/MMBtu**	4. Equivalent Allowable Emissions: **128.8** lb/hour **564.1** tons/year
5. Method of Compliance: **EPA Method 7 or 7E.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing.** **Permit No. 1110003-005-AV.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.3 lb/MMBtu**	4. Equivalent Allowable Emissions: **193.2** lb/hour **38.64** tons/year
5. Method of Compliance: **EPA Method 7 or 7E.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing.** **Permit No. 1110003-005-AV/OGC Case No. 91-1610.** **Total combined emissions of Boiler Unit Nos. 6, 7, and 8 limited to 622 TPY.**	

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: **622 TPY**	4. Equivalent Allowable Emissions: lb/hour **622** tons/year
5. Method of Compliance: **EPA Method 7 or 7E.**	
6. Allowable Emissions Comment (Description of Operating Method): **OGC Case No. 91-1610** **Combined annual emissions of Boiler Unit Nos. 6, 7, and 8 limited to 622 TPY.**	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **17.01** lb/hour **45.3** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5 lb/1000 gallons** Reference: **Table 1.3-1, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Emission factor = 5 lb/1000 gallons x 1000 gallons/138 MMBtu = 0.0362 lb/MMBtu
Hourly emissions = 0.0362 lb/MMBtu x 644 MMBtu/hr = 23.31 lb/hr

Total combined emissions of Boiler Unit Nos. 6, 7, and 8 limited to 45.3 TPY.

11. Potential Fugitive and Actual Emissions Comment:

Hourly emissions based on oil firing.

Annual emissions based on 400 hours of oil firing and 8,360 hrs/yr of natural gas-firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **12.59 lb/hr**	4. Equivalent Allowable Emissions: **12.59** lb/hour **45.3** tons/year
5. Method of Compliance: **EPA Method 10.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing.** **Permit No. 1110003-005-AV / OGC Case No. 91-1610.** **Total combined emissions of Boiler Unit Nos. 6, 7, and 8 limited to 45.3 TPY.**	

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: **45.3 TPY**	4. Equivalent Allowable Emissions: lb/hour **45.3** tons/year
5. Method of Compliance: **EPA Method 10.**	
6. Allowable Emissions Comment (Description of Operating Method): **Total combined emissions of Boiler Unit Nos. 6, 7, and 8 limited to 45.3 TPY.** **OGC Case No. 91-1610.**	

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/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.934** lb/hour **2.03** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.2 lb/1000 gallons** Reference: **Table 1.3-3, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Emission factor = 0.2 lb/1000 gallons x 1000 gallons/138 MMBtu = 0.00145 lb/MMBtu
Hourly emissions = 0.00145 lb/MMBtu x 644 MMBtu/hr = 0.934 lb/hr
Annual emissions = (0.00145 lb/MMBtu x 644 MMBtu/hr x 400 hrs/yr) + (0.441 lb/hr x 8,360 hrs/yr) x 1 TPY/2,000 lbs = 2.03 TPY

11. Potential Fugitive and Actual Emissions Comment:
Hourly emissions based on oil firing.

Annual emissions based on 400 hours of oil firing and 8,360 hrs/yr of natural gas-firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **0.441 lb/hr**	4. Equivalent Allowable Emissions: **0.441** lb/hour **1.93** tons/year
5. Method of Compliance: **EPA Method 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing.** **Permit No. 1110003-005-AV / OGC Case No. 91-1610.**	

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: **2.3 TPY**	4. Equivalent Allowable Emissions: lb/hour **2.3** tons/year
5. Method of Compliance: **EPA Method 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Total combined emissions of Boiler Unit Nos. 6, 7, and 8 limited to 2.3 TPY.** **OGC Case No. 91-1610.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 4

1. Visible Emissions Subtype: **VE5**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **5** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE test using EPA Method 9**	
5. Visible Emissions Comment: **Visible emissions limited to 5 percent opacity when firing natural gas. Permit No. 1110003-005-AV.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 4

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: **DEP Method 9**	
5. Visible Emissions Comment: **Visible emissions limited to 20 percent opacity when firing fuel oil. Permit No. 1110003-005-AV.**	

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 3 of 4

1. Visible Emissions Subtype: **VE60**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **60** % Exceptional Conditions: **>60** % Maximum Period of Excess Opacity Allowed: **4 periods of 6** min/hour	
4. Method of Compliance: **VE test using EPA Method 9**	
5. Visible Emissions Comment: **Rule 62-210.700(3), F.A.C. and Permit No. 1050003-013-AV.** **60 percent opacity during load changing and boiler cleaning (soot blowing) for 3 hours in any 24 hour period.** **Annual VE test required if >400 hrs/yr oil operation.**	

Visible Emissions Limitation: Visible Emissions Limitation 4 of 4

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: **None**	
5. Visible Emissions Comment: **Rule 62-210.700(1), F.A.C. for excess emissions during startup, shutdown, or malfunction. Excess emissions limited to 2 hours in any 24-hour period.**	

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo Environmental** Model Number: **42D**	Serial Number: **47986-279**
5. Installation Date: **1/7/94**	6. Performance Specification Test Date: **1/11/94**
7. Continuous Monitor Comment: **40 CFR Part 75**	

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code:	2. Pollutant(s): **CO_2**
3. CMS Requirement:	☒ Rule ☐ Other
4. Monitor Information... Manufacturer: **Thermo Environmental** Model Number: **41H**	Serial Number: **41H-48183**
5. Installation Date: **1/7/94**	6. Performance Specification Test Date: **1/11/94**
7. Continuous Monitor Comment: **40 CFR Part 75**	

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: **FPU-EU3-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: **FPU-EU1-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 _____
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: **FPU-EU3-I4** ☐ Previously Submitted, Date _____
   ☐ 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: **August 22, 2006**

   ☐ To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: _____ ☒ Not Applicable

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 (Rule 62-212.400(4)(d), F.A.C., and Rule 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	

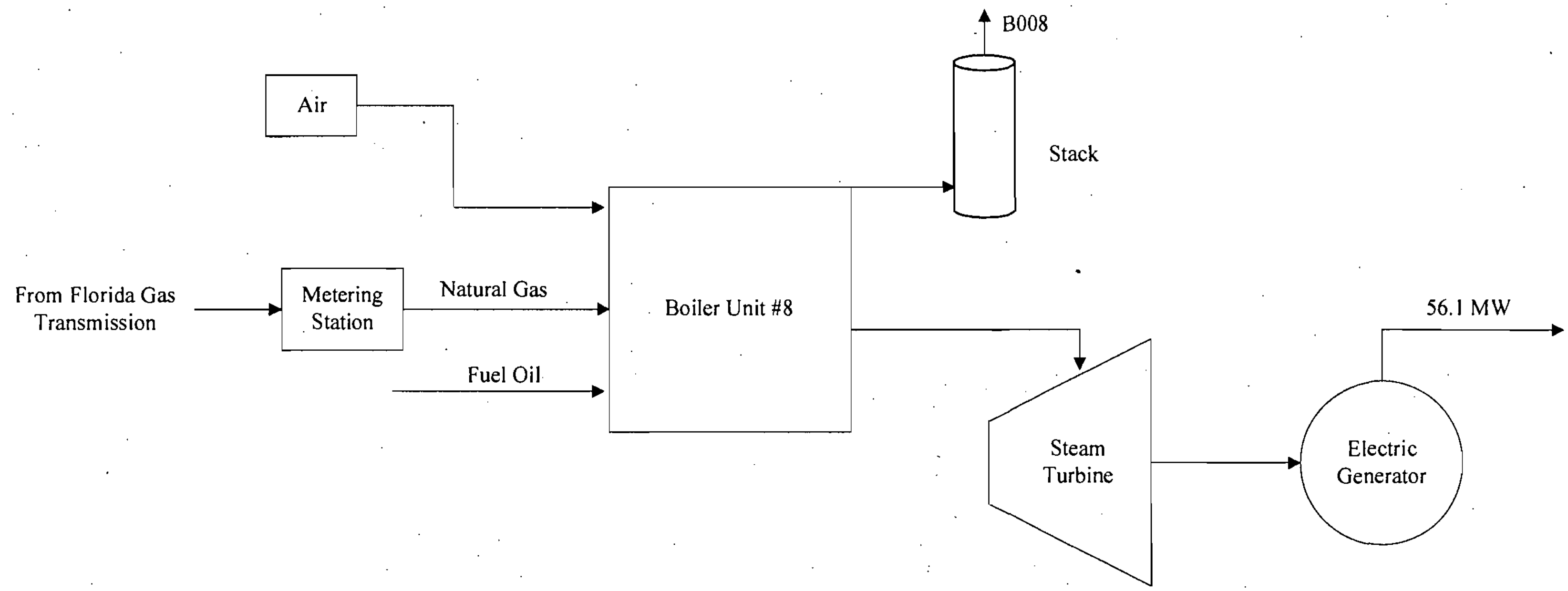
Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☒ Attached, Document ID: **FPU-EU1-IV1** ☐ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: _____ ☒ Not Applicable	
3. Alternative Methods of Operation ☒ Attached, Document ID: **FPU-EU3-IV3** ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: _____ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: _____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: _____ ☒ Previously Submitted, Date: _____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date: _____ ☐ Not Applicable	

Additional Requirements Comment

ATTACHMENT FPU-EU3-I1

PROCESS FLOW DIAGRAM



Attachment FPU-EU3-I1
56.1 MW Boiler Unit #8
Process Flow Diagram
Fort Pierce Utilities - H.D. King Power Plant
Fort Pierce, Florida

Process Flow Legend
Solid/Liquid
Gas
Steam

Filename: 07387523/PROCESS FLOW DIAGRAMS.VSD
Date: 06/18/07

Golder Associates

ATTACHMENT FPU-EU3-I4

PROCEDURES FOR STARTUP AND SHUTDOWN

NO. 8 BOILER PRELIGHT CHECK LIST

PURPOSE

This procedure has been prepared to serve as a guide to ensure that all systems and related equipment pertaining to the prelight of a steam generator is properly inspected and determined that it is fully functional prior to putting equipment into service.

SCOPE

As a safety precaution, responsibilities are listed in checklist form to ensure proper inspection of boilers by the Operators and acknowledged by the Watch Engineer. This does not necessarily dictate the order in which equipment is checked out, nor is it all inclusive and should not be relied on as a substitute for good operating practice based on individual experience and training.

POLICY

The check list will be preformed and checked off before attempting to place equipment/prelight of steam generators into service.

GENERAL

The No. 8 Boiler Prelight Check List for the prospective unit will be properly filled out by both the Operator and the Watch Engineer and then turned in to the Plant Operations Supervisor.

PREPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.:
[signature] Tudor, Jr.	[signature]	POWER PLANT	2-12-92	0

NO. 8 BOILER PRELIGHT CHECK LIST

OPER	1.	DRUM LEVEL IS UP TO FIRING LEVEL (1 BUBBLE IN SIGHTGLASS.)	☐
OPER	2.	CHECK ALARM PANELS IN BOILER ROOM AND TURBINE PANEL, TEST ALARMS, REPLACE BULBS AS NECESSARY. PLACE MOLYTEKS IN AUTO MODE (BOILER ROOM AND TURBINE BOARD.)	☐
W.ENG	3.	CHECK FOR TAGS ON EQUIPMENT IN BOILER ROOM, TURBINE PANEL, 2400 V BUS AND 480 V BUS.	☐
OPER	4.	TAKE NITROGEN BLANKET OFF BOILER, CLOSE VALVE AT BOILER AND SHUT FLOW OFF AT SCAVENGER.	☐
OPER	5.	CHECK ALL BOILER ENTRANCE DOORS TO MAKE SURE THEY ARE SECURE, MAKE SURE THERE IS NO WATER LEAKAGE FROM BOILER DRUM HATCHES AND THAT THEY ARE SECURE.	☐
OPER	6.	OPEN BOILER VENTS (3) SUPERHEATER OUTLET, AFTER SPRAY HEADER, AND NORTH DRUM VENT.	☐
OPER	7.	OPEN BOILER DRAINS (2) MAIN, SPRAY HEADER DRAIN (UPSTREAM AND DOWNSTREAM VALVES.)	☐
OPER	8.	VALVES BEFORE AND AFTER ATTEMPERATOR ARE OPEN (BY-PASS CLOSED,) AND DOWNSTREAM VALVE AT TOP OF BOILER OPEN.	☐
OPER	9.	VALVES OPEN BEFORE AND AFTER FEEDWATER REGULATOR (BYPASS VALVE CLOSED.)	☐
OPER	10.	CHECK POSITION OF FEEDWATER STOP VALVE.	☐
OPER	11.	NORTH AND SOUTH BOILER BLOWDOWN VALVES SHOULD BE CLOSED. BLOWDOWNS SHOULD BE LINED UP TO FLASH TANK.	☐
OPER	12.	NORTH AND SOUTH SIDE WATERWALL HEADER DRAINS SHOULD BE CLOSED.	☐

PREPARED BY:	APPROVED BY:	H. D. KING POWER PLANT	DATE ISSUED:	REVISION NO.:
[signature]	[initials]		2-12-92	0

NO. 8 BOILER PRELIGHT CHECK LIST (CON'T.)

OPER	13.	CHECK OUT BOILER FEEDWATER PUMPS. (A) SUCTION AND DISCHARGE VALVES OPEN. (B) VENTS OPEN. (C) BALANCE LINE VALVES OPEN AT PUMP AND AT DA. (D) CHECK OIL LEVEL IN RESERVOIR. (E) CHECK IN BOWL FOR SHAFT PUMP SUCTION. (F) RECIRC VALVE AT DA AND VALVES AT PUMP OPEN. (G) ALL COOLING WATER VALVES OPEN. (H) AUX LUBE OIL PUMP IN AUTO. (I) RECIRC VALVES IN MANUAL OPEN POSITION IN BOILER ROOM.	☐
OPER	14.	CHECK OIL LEVELS AT FORCED DRAFT FANS AND MOTORS.	☐
OPER	15.	OPEN MANUAL FAN AND STACK DAMPERS ON FAN TO BE PLACED IN SERVICE.	☐
OPER	16.	CHECK OIL LEVELS OF AIRHEATER TRUNION BEARINGS (HOT AND COLD ENDS); ALSO, COOLING WATER TO AIRHEATER BEARINGS	☐
OPER	17.	COOLING WATER TO AIRHEATER SHAFTS ON.	☐
OPER	18.	CHECK OIL LEVELS OF AIR HEATER MOTORS AND AIR DRIVES.	☐
ER	19.	TURN ON O2 ANALYZER AND CHECK CALIBRATION.	☐
OPER	20.	TURN ON NOX RECORDER AS USUAL.	☐
OPER	21.	CHECK OUT EACH BURNER AT FRONT. (A) PILOT IN AUTO POSITION. (B) AIR REGISTER OPERATION. (C) LIMIT SWITCHES IN PROPER POSITION. (D) COOLING AIR VALVES OPEN, SEALING VALVES CLOSED. (E) BURNER GUN OPERATION. (F) ALL OTHER RELATED EQUIPMENT.	☐
OPER	22.	CHECK FORNEY BURNER CABINETS AND NOTIFY WATCH ENGINEER OF ANY TAGS.	☐
OPER	23.	COOLING AIR VALVES TO PORTHOLES ARE OPEN.	☐
OPER	24.	HOUSE AIR COMPRESSOR IS ON (PRESS. A MIN. OF 85 PSI.)	☐

PREPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.:
Edwin Theda, Jr.	TR	POWER PLANT	2-12-92	0

NO. 8 BOILER PRELIGHT CHECK LIST (CON'T.)

OPER 25. MAKE-UP PUMP IS LINED TO DA.

OPER 26. MAKE SURE WE HAVE FULL INSTRUMENT AIR PRESSURE. VALVES AT FILTERS SHOULD BE OPEN.

OPER 27. CHECK FIBERGLASS TANK LEVEL.

OPER 28. BALOMETER HAS BEEN CLEANED.

OPER 29. THERMO PROBE IS RETRACTED (UNLESS OTHERWISE INSTRUCTED BY WATCH ENGINEER.)

W ENG 30. DRUM LEVEL TRIP IS LIFTED.

OPER 31. COOLING AIR BLOWER IS ON, RESERVE IS ON STANDBY.

OPER 32. MAIN STEAM STOP VALVE IS OPEN (UNLESS OTHERWISE INSTRUCTED BY WATCH ENGINEER.)

OPER 33. CHECK IGNITOR GAS SUPPLY (12 - PSI CITY OF FLORIDA GAS.)

OPER 34. CHECK YARD GAS VALVES, OPEN S-4 VALVE AT GAS HEADER ON PLATFORM. MAKE SURE MINIMUM FLOW VALVE IS FULLY OPEN, AND THE MAIN GAS VALVE BEFORE MAIN REDUCER IS CLOSED (UNTIL WE ARE ON THE LINE.)

OPER 35. INFORM CONTROL ROOM YOU ARE GOING TO BE STARTING A FORCED DRAFT FAN.

OPER 36. START FAN AND INITIATE PURGE. CHECK FAN FOR VIBRATION AND OIL SLINGERS FOR PROPER OPERATION.

OPER 37. BE PREPARED TO PUT FIRE IN BOILER AND BRING BOILER UP AS USUAL.

OPER 38. SIGN NOX CHART (TIME FIRE WAS PUT IN BOILER.)

W ENG 39. NOTIFY FLORIDA GAS IF UNIT IS COMING ON LINE.

PREPARED BY:	APPROVED BY:	H. D. KING POWER PLANT	DATE ISSUED:	REVISION NO.:
[illegible]			2-12-92	0

NO. 8 BOILER PRELIGHT CHECK LIST (CON'T.)

COMMENTS/ACTIONS TAKEN THAT WERE NECESSARY IN ORDER TO PUT EQUIPMENT INTO SERVICE/PRELIGHT BOILER:

CONTROL/ BOILER OPER____________________

WATCH ENGINEER____________________

Date____________________

PREPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.:
[signature]	[initials]	POWER PLANT	2-12-92	0

#8 UNIT SHUTDOWN PROCEDURE

1 Boiler room lowers boiler pressure 50 to 100 psi. (from 1250 to 1150 psi)

2 Control room lowers generator to about 3 megawatts.

3 Boiler room takes gas fire out of boiler and starts a boiler purge and tells control room to take unit off line.

4 Control room operator lowers the generator voltage down from [illegible].2KV to 13.5KV

5 Control room operator lowers generator down to zero MW. When the generator watthour meter stops turning the control room operator opens the generator breaker and the field breaker.

6 When generator is off line the control room operator informs the shift supervisor and he/she will close the throttle valve stopping the turbine.

7 Auxiliary operator controls condenser/hotwell and deaerating heater (DA) levels until the DA temperature is below 212 degrees and then pertaining auxiliary equipment is shutdown.

8 Shift supervisor places turbine-generator on turning gear once the turbine rolls down to zero speed.

9 Once the boiler has completed its 5 min. purge the FD fan is shut down and all gas valves are closed pertaining to the unit.

ATTACHMENT FPU-EU3-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT FPU-EU3-IV3

ALTERNATIVE METHODS OF OPERATION
UNIT 8

Fossil fuel-fired steam generator Unit No. 8 is fired with natural gas as a primary fuel. No. 2 fuel oil is fired as a secondary/emergency fuel. Fuel oil firing in Boiler Unit Nos. 6, 7, and 8 is limited to a combined total of 400 hours per year.

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 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 for air permit. 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 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/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. **The air construction permitting classification must be used to complete the Emissions Unit Information Section of this application for air permit.** 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 construction permitting and insignificant emissions units are required to be listed at Section II, Subsection C.

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

A. GENERAL EMISSIONS UNIT INFORMATION

Title V Air Operation Permit Emissions Unit Classification

1. Regulated or Unregulated Emissions Unit? (Check one, if applying for an initial, revised or renewal Title V air operation permit. Skip this item if applying for an air construction permit or FESOP only.) ☒ The emissions unit addressed in this Emissions Unit Information Section is a regulated emissions unit. ☐ The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

Emissions Unit Description and Status

1. Type of Emissions Unit Addressed in this Section: (Check one) ☒ This Emissions Unit Information Section addresses, as a single emissions unit, a single process or production unit, or activity, which produces one or more air pollutants and which has at least one definable emission point (stack or vent). ☐ This Emissions Unit Information Section addresses, as a single emissions unit, a group of process or production units and activities which has at least one definable emission point (stack or vent) but may also produce fugitive emissions. ☐ This Emissions Unit Information Section addresses, as a single emissions unit, one or more process or production units and activities which produce fugitive emissions only.				
2. Description of Emissions Unit Addressed in this Section: **16.5 MW Boiler - Unit No. 6**				
3. Emissions Unit Identification Number: **004**				
4. Emissions Unit Status Code: **A**	5. Commence Construction Date:	6. Initial Startup Date: **1/4/58**	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? ☐ Yes ☒ No
9. Package Unit: Manufacturer: **Westinghouse** Model Number: **13-A-1685-1**				
10. Generator Nameplate Rating: **16.5** MW				
11. Emissions Unit Comment: **Emission unit is a 16.5-MW natural gas-fired steam electric generator. No. 2 fuel oil is used as backup. Emission unit did not operate during the last 1 year and is in extended shutdown situation.**				

Emissions Unit Control Equipment

1. Control Equipment/Method(s) Description: **Multiple cyclone**	
2. Control Device or Method Code(s): **76**	

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: **218.9** million Btu/hr	
4. Maximum Incineration Rate: pounds/hr tons/day	
5. Requested Maximum Operating Schedule: **24** hours/day **7** days/week **52** weeks/year **8,760** hours/year	
6. Operating Capacity/Schedule Comment: **Maximum heat input based on natural gas or No. 2 fuel oil firing.** **Natural gas is used as primary fuel with No. 2 fuel oil used as backup.** **Combined annual heat input from EUs 004 (16.5 MW Boiler - Unit No. 6), 007 (37.5 MW Boiler Unit No. 7), and 008 (56.1 MW Boiler - Unit No. 8) limited to 4,534,930 MMBtu/yr.** **Combined annual fuel oil usage from EUs 004 (16.5 MW Boiler - Unit No. 6), 007 (37.5 MW Boiler Unit No. 7), and 008 (56.1 MW Boiler - Unit No. 8) limited to 400 hrs/yr.**	

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: **No. 6 Boiler**	2. Emission Point Type Code: **1**

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:
004

5. Discharge Type Code: **V**	6. Stack Height: **148** feet	7. Exit Diameter: **5** feet
8. Exit Temperature: **325** °F	9. Actual Volumetric Flow Rate: **42,735** acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates... Zone: **17** East (km): **566.8** North (km): **3,036.3**	14. Emission Point Latitude/Longitude... Latitude (DD/MM/SS) **27/27/00** Longitude (DD/MM/SS) **80/19/26**

15. Emission Point Comment:
Exit temperature and exhaust flow rate are from Title V permit application dated July 2002.

D. SEGMENT (PROCESS/FUEL) INFORMATION

Segment Description and Rate: Segment 1 of 2

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 natural gas burned**	
4. Maximum Hourly Rate: **0.212**	5. Maximum Annual Rate: **1,856**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,033**
10. Segment Comment: **Maximum hourly rate = 218.9 MMBtu/hr /1033 MMBtu/MMft^3 = 0.212 MMft^3/hr** **Maximum annual rate = 218.9 MMBtu/hr /1033 MMBtu/MMft^3 x 8,760 hrs/yr = 1,856.3 MMft^3/hr** **Combined annual heat input from Boiler Unit No. 6, Boiler Unit No. 7, and Boiler Unit No. 8 limited to 4,534,930 MMBtu/yr.**		

Segment Description and Rate: Segment 2 of 2

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: **1.586**	5. Maximum Annual Rate: **635**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **138**
10. Segment Comment: **Maximum hourly rate = 218.9 MMBtu/hr /138 MMBtu/1,000 gallon = 1586.2 gallons/hr.** **Maximum annual rate = 1586.2 gallons/hr x 400 hr/yr = 634.5x10^3 gallons/yr.** **Combined annual fuel oil usage from EUs 004 (16.5 MW Boiler - Unit #6), 007 (37.5 MW Boiler Unit No. 7), and 008 (56.1 MW Boiler - Unit No. 8) limited to 400 hrs/yr.**		

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
PM	76		EL
PM_{10}	76		NS
CO			EL
VOC			EL
SO_2			EL
NO_x			EL

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **65.7** lb/hour **14.81** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.3 lb/MMBtu** Reference: **62-210.700(3), F.A.C.**	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:

Hourly emissions = 0.3 lb/MMBtu x 218.9 MMBtu/hr = 65.67 lb/hr (Oil firing, soot blowing scenario)

Annual emissions = (0.3 lb/MMBtu x 218.9 MMBtu/hr x 400 hrs/yr) + (0.4 lb/hr x 8,360 hr/yr) x 1 TPY/2,000 lbs = 14.81 TPY

11. Potential Fugitive and Actual Emissions Comment:

Hourly emissions based on soot blowing while oil firing.

Annual emissions based on 400 hours of oil firing (soot blowing) and 8,360 hr/yr of natural gas-firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **0.4 lb/hr**	4. Equivalent Allowable Emissions: **0.4** lb/hour **1.8** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing. Permit No. 1110003-005-AV / OGC Case No. 91-1610. Annual compliance test not required if firing only natural gas or if oil firing for less than 400 hr/yr.**	

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: **0.3 lb/MMBtu**	4. Equivalent Allowable Emissions: **65.7** lb/hour **13.1** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on oil firing during soot blowing operations. Rule 62-210.700(3), F.A.C. and Permit No. 1110003-005-AV. Annual emissions based on oil firing (soot blowing) for 400 hr/yr. Compliance test required if oil firing >400 hr/yr.**	

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: **16 TPY**	4. Equivalent Allowable Emissions: lb/hour **16** tons/year
5. Method of Compliance: **EPA Method 5**	
6. Allowable Emissions Comment (Description of Operating Method): **Combined emissions from Boiler Unit Nos. 6, 7, and 8 limited to 16 TPY. OGC Case No. 91-1610.**	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **175.12** lb/hour **45.5** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.8 lb/MMBtu** Reference: **1050003-013-AV/AC 56-141460A / OGC Case 91-1610.**	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:

Hourly emissions = 0.8 lb/MMBtu x 218.9 MMBtu/hr = 175.12 lb/hr (Oil firing)

Annual emissions = (0.8 lb/MMBtu x 218.9 MMBtu/hr x 400 hr/yr) + (2.5 lb/hr x 8,360 hr/yr) x 1 TPY/2,000 lbs = 45.47 TPY

11. Potential Fugitive and Actual Emissions Comment:

Hourly emissions based on oil firing.

Annual emissions based on 400 hours of oil firing and 8,360 hr/yr of natural gas-firing.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **2.5 lb/hr**	4. Equivalent Allowable Emissions: **2.5** lb/hour **11.0** tons/year
5. Method of Compliance: **EPA Method 6 or 6C or fuel analysis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing.** **Permit No. 1110003-005-AV / AC 56-141460A.**	

Allowable Emissions Allowable Emissions 2 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Allowable Emissions and Units: **0.8 lb/MMBtu**	4. Equivalent Allowable Emissions: **175.12** lb/hour **35.02** tons/year
5. Method of Compliance: **EPA Method 6 or 6C or fuel analysis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on oil firing.** **Permit No. 1110003-005-AV / AC 56-141460A.** **Annual emissions based on oil firing for 400 hr/yr.**	

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: **101.6 TPY**	4. Equivalent Allowable Emissions: lb/hour **101.6** tons/year
5. Method of Compliance: **EPA Method 6 or 6C or fuel analysis.**	
6. Allowable Emissions Comment (Description of Operating Method): **Combined emissions from Boiler Unit Nos. 6, 7, and 8 limited to 101.6 TPY.** **OGC Case No. 91-1610.**	

F1. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION – POTENTIAL/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **38.1** lb/hour **13.1** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **24 lb/1,000 gallons** Reference: **Table 1.3-1, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Emission factor = 24 lb/1,000 gallons x 1,000 gal/138 MMBtu = 0.1739 lb/MMBtu
Hourly emissions = 0.1739 lb/MMBtu x 218.9 MMBtu/hr = 38.07 lb/hr
Annual emissions = (0.1739 lb/MMBtu x 218.9 MMBtu/hr x 400 hr/yr) + (1.31 lb/hr x 8,360 hrs/yr) x 1 TPY/2,000 lbs = 13.09 TPY

11. Potential Fugitive and Actual Emissions Comment:
Hourly emissions based on oil firing.

Annual emissions based on 400 hours of oil firing and 8,360 hr/yr of natural gas-firing. Hourly emissions due to natural gas firing limited to 1.31 lb/hr.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **1.31 lb/hr**	4. Equivalent Allowable Emissions: **1.31** lb/hour **5.74** tons/year
5. Method of Compliance: **EPA Method 7 or 7E.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing. Permit No. 1110003-005-AV / OGC Case No. 91-1610.**	

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: **622 TPY**	4. Equivalent Allowable Emissions: lb/hour **622** tons/year
5. Method of Compliance: **EPA Method 7 or 7E.**	
6. Allowable Emissions Comment (Description of Operating Method): **Total combined emissions of Boiler Unit Nos. 6, 7, and 8 limited to 622 TPY. Permit No. 1110003-005-AV / OGC Case No. 91-1610.**	

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/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **7.93** lb/hour **2.21** tons/year	4. Synthetically Limited? ☒ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **5 lb/1000 gallons** Reference: **Table 1.3-1, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:

Emission factor = 5 lb/1,000 gallons x 1,000 gal/138 MMBtu = 0.0362 lb/MMBtu
Hourly emissions = 0.0362 lb/MMBtu x 218.9 MMBtu/hr = 7.93 lb/hr
Annual emissions = (0.0362 lb/MMBtu x 218.9 MMBtu/hr x 400 hr/yr) + (0.15 lb/hr x 8,360 hr/yr) x 1 TPY/2,000 lbs = 2.21 TPY

11. Potential Fugitive and Actual Emissions Comment:

Hourly emissions based on oil firing.

Annual emissions based on 400 hours of oil firing and 8,360 hr/yr of natural gas-firing. Hourly emissions due to natural gas firing limited to 0.15 lb/hr.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **0.15 lb/hr**	4. Equivalent Allowable Emissions: **0.15** lb/hour **0.66** tons/year
5. Method of Compliance: **EPA Method 10.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing.** **Permit No. 1110003-005-AV / OGC Case No. 91-1610.**	

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: **45.3 TPY**	4. Equivalent Allowable Emissions: lb/hour **45.3** tons/year
5. Method of Compliance: **EPA Method 10.**	
6. Allowable Emissions Comment (Description of Operating Method): **Total combined emissions of Boiler Unit Nos. 6, 7, and 8 limited to 45.3 TPY.** **Permit No. 1110003-005-AV / OGC Case No. 91-1610.**	

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/ESTIMATED FUGITIVE EMISSIONS

(Optional for unregulated emissions units.)

Potential/Estimated Fugitive Emissions

Complete 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 permit. Complete for each emissions-limited pollutant identified in Subsection E if applying for an air operation permit.

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **0.32** lb/hour **0.162** tons/year	4. Synthetically Limited? ☐ Yes ☐ No
5. Range of Estimated Fugitive Emissions (as applicable): to tons/year	
6. Emission Factor: **0.2 lb/1,000 gallons** Reference: **Table 1.3-3, AP-42**	7. Emissions Method Code: **3**
8.a. Baseline Actual Emissions (if required): tons/year	8.b. Baseline 24-month Period: From: To:
9.a. Projected Actual Emissions (if required): tons/year	9.b. Projected Monitoring Period: ☐ 5 years ☐ 10 years

10. Calculation of Emissions:
Emission factor = 0.2 lb/1,000 gallons x 1,000 gallons/138 MMBtu = 0.00145 lb/MMBtu
Hourly emissions = 0.00145 lb/MMBtu x 218.9 MMBtu/hr = 0.317 lb/hr
Annual emissions = (0.00145 lb/MMBtu x 218.9 MMBtu/hr x 400 hr/yr) + (0.0236 lb/hr x 8,360 hrs/yr) x 1 TPY/2,000 lbs = 0.162 TPY

11. Potential Fugitive and Actual Emissions Comment:
Hourly emissions based on oil firing.

Annual emissions based on 400 hours of oil firing and 8,360 hr/yr of natural gas-firing. Hourly emissions due to natural gas firing limited to 0.0236 lb/hr.

F2. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION - ALLOWABLE EMISSIONS

Complete 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: **0.0236 lb/hr**	4. Equivalent Allowable Emissions: **0.0236** lb/hour **0.103** tons/year
5. Method of Compliance: **EPA Method 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Allowable emissions based on natural gas firing. Permit No. 1110003-005-AV / OGC Case No. 91-1610.**	

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: **2.3 TPY**	4. Equivalent Allowable Emissions: lb/hour **2.3** tons/year
5. Method of Compliance: **EPA Method 25A.**	
6. Allowable Emissions Comment (Description of Operating Method): **Total combined emissions of Boiler Unit Nos. 6, 7, and 8 limited to 2.3 TPY. Permit No. 1110003-005-AV / OGC Case No. 91-1610.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 4

1. Visible Emissions Subtype: **VE5**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **5** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE test using EPA Method 9**	
5. Visible Emissions Comment: **Visible emissions limited to 5% opacity when firing natural gas. Permit No. 1110003-005-AV.**	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 4

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: ☐ Rule ☒ Other
3. Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: **40** % Maximum Period of Excess Opacity Allowed: **2** min/hour	
4. Method of Compliance: **DEP Method 9**	
5. Visible Emissions Comment: **Visible emissions limited to 20% opacity when firing fuel oil. Permit No. 1110003-005-AV.**	

G. VISIBLE EMISSIONS INFORMATION

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

Visible Emissions Limitation: Visible Emissions Limitation 3 of 4

1. Visible Emissions Subtype: **VE60**	2. Basis for Allowable Opacity: ☒ Rule ☐ Other
3. Allowable Opacity: Normal Conditions: **60** % Exceptional Conditions: **>60** % Maximum Period of Excess Opacity Allowed: **4 periods of 6** min/hour	
4. Method of Compliance: **VE test using EPA Method 9**	
5. Visible Emissions Comment: **Rule 62-210.700(3), F.A.C. and Permit No. 1050003-013-AV.** **60 percent opacity during load changing and boiler cleaning (soot blowing) for 3 hours in any 24-hour period.** **Annual VE test required if >400 hr/yr oil operation.**	

Visible Emissions Limitation: Visible Emissions Limitation 4 of 4

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: **None**	
5. Visible Emissions Comment: **Rule 62-210.700(1), F.A.C. for excess emissions during startup, shutdown, and malfunction. Excess emissions limited to 2 hours in 24-hour period.**	

EMISSIONS UNIT INFORMATION
Section [4]
16.5 MW Boiler - Unit #6

H. CONTINUOUS MONITOR INFORMATION

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

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number: 132
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code:	2. Pollutant(s):
3. CMS Requirement:	☐ Rule Other
4. Monitor Information... Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment:	

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: FPU-EU4-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: FPU-EU1-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: FPU-EU4-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 _____
   ☐ Not Applicable (construction application)
5. Operation and Maintenance Plan (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID: _____ ☐ Previously Submitted, Date _____
   ☒ Not Applicable
6. Compliance Demonstration Reports/Records
   ☐ Attached, Document ID: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ Previously Submitted, Date: _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☐ To be Submitted, Date (if known): _____
   Test Date(s)/Pollutant(s) Tested: _____

   ☒ Not Applicable

   Note: For FESOP applications, all required compliance demonstration records/reports must be submitted at the time of application. For Title V air operation permit applications, all required compliance demonstration reports/records must be submitted at the time of application, or a compliance plan must be submitted at the time of application.
7. Other Information Required by Rule or Statute
   ☐ Attached, Document ID: _____ ☒ Not Applicable

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 (Rule 62-212.400(4)(d), F.A.C., and Rule 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	

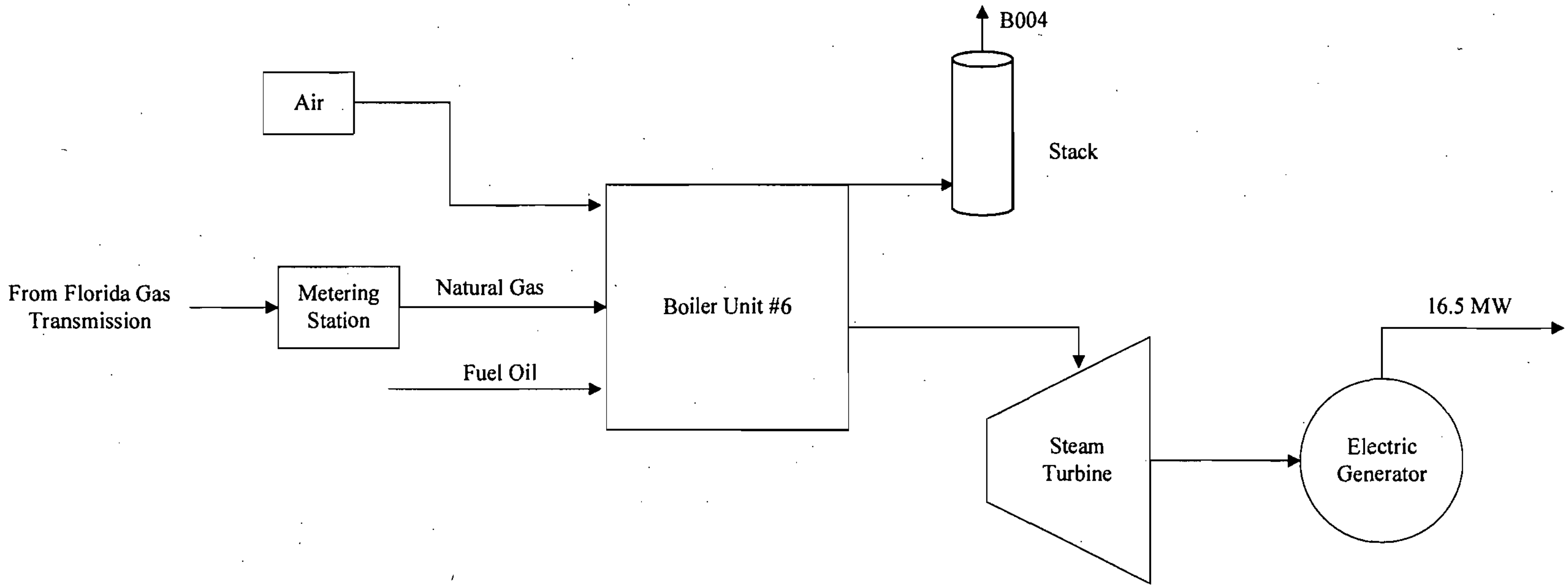
Additional Requirements for Title V Air Operation Permit Applications

1. Identification of Applicable Requirements ☒ Attached, Document ID: FPU-EU1-IV1 ☐ Not Applicable	
2. Compliance Assurance Monitoring ☐ Attached, Document ID: ____ ☒ Not Applicable	
3. Alternative Methods of Operation ☒ Attached, Document ID: FPU-EU4-IV3 ☐ Not Applicable	
4. Alternative Modes of Operation (Emissions Trading) ☐ Attached, Document ID: ____ ☒ Not Applicable	
5. Acid Rain Part Application ☐ Certificate of Representation (EPA Form No. 7610-1) ☐ Copy Attached, Document ID: ____ ☐ Acid Rain Part (Form No. 62-210.900(1)(a)) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ New Unit Exemption (Form No. 62-210.900(1)(a)2.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☐ Phase II NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) ☐ Attached, Document ID: ____ ☐ Previously Submitted, Date: ____ ☒ Not Applicable	

Additional Requirements Comment

ATTACHMENT FPU-EU4-I1

PROCESS FLOW DIAGRAM



Attachment FPU-EU4-I1 56.1 MW Boiler Unit #6 Process Flow Diagram Fort Pierce Utilities - H.D. King Power Plant Fort Pierce, Florida	**Process Flow Legend** Solid/Liquid ⟶ Gas ⟶ Steam ⟶	Filename: 07387523/FPU-EU4-I1 .VSD Date: 6/19/07 Golder Associates

ATTACHMENT FPU-EU4-I3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

CYCLONES

PRAT-DANIEL CORPORATION

POWER PLANT EQUIPMENT

Executive Offices and Plant
South Norwalk, Conn.

Fans, Stacks
Dust Collectors
Air Heaters
Thermobloc
Industrial Heaters

Project & Sales Engineers
THE THERMIX CORPORATION
Greenwich, Connecticut

JOB SUMMARY

The Babcock & Wilcox Company
P. O. #777-232523 Gr. 89
City of Fort Pierce, Fla.
Prat-Daniel File 357-55

(1) Design 6UPHT #18-386 Prat-Daniel Tubular Dust Collector, 3/16" Corten steel hoppers, inlet damper, water washing system

PERFORMANCE: Elev. Sea Level Bar.: 30" Hg.

Lbs. gas per hour	242,000
Temperature deg. F.	350
Collector resistance, "w.g.	2.5

Collection efficiency based on Curve CO-31-E.

MM:MMT
5/15/56

ATTACHMENT FPU-EU4-IV3

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT FPU-EU4-IV3

ALTERNATIVE METHODS OF OPERATION

UNIT 6

Fossil fuel-fired steam generator Unit No. 6 is fired with natural gas as a primary fuel. No. 2 fuel oil is fired as a secondary/emergency fuel. Fuel oil firing in Boiler Unit Nos. 6, 7, and 8 is limited to a combined total of 400 hours per year.