RECEIVED
JUL 05 2002
BUREAU OF AIR REGULATION

Working copy

TITLE V PERMIT RENEWAL APPLICATION
FLORIDA POWER & LIGHT COMPANY
FORT MYERS POWER PLANT
FT. MYERS, FLORIDA

Prepared For:
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

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

July 2002
0237560

DISTRIBUTION:
4 Copies - FDEP Bureau of Air Regulation
1 Copy – FDEP South District
1 Copy – Florida Power & Light Company
1 Copy – Florida Power & Light Ft. Myers Power Plant
1 Copy – Golder Associates Inc.

Florida Power & Light Company, Environmental Services Dept., P.O. Box 14000, Juno Beach,FL 33408

FPL

RECEIVED
JUL 05 2002
BUREAU OF AIR REGULATION

June 27, 2002

Scott M. Sheplak
Bureau of Air Regulation
State of Florida
Department of Environmental Protection
2600 Blair Stone Road
Mail Station #5505
Tallahassee, FL 32399-2400

Re: Title V Permit Renewal Application; Ft. Myers Power Plant, 0710002-010-AV;

Dear Scott,

Enclosed are four copies of the Title V Permit renewal application for the Ft. Myers Power Plant. Also included are 2 diskettes; 1 with the renewal application and the other associated Word format documents, and another with the associated drawings. The diskettes, unfortunately, do not contain all of the attachments or drawings that accompany the hard copy application.

The combined cycle Combustion Turbines (2A-2F) are going through their compliance testing in the combined cycle configuration at the time of this application's submittal, therefore, the complete results of the testing will be forwarded to you under separate cover. In addition, provisions for visible emissions (VE) testing (agency notification, load dispatcher clearances, etc.) are in progress to test three of the simple cycle Gas Turbines (GTs 1-12) as required for permit renewal. The VE test reports will be forwarded under separate cover, as well.

Thanks for your assistance in this matter, and, if you should have any questions, please do not hesitate to contact me at (561) 691-2877.

Very Truly yours,

Kevin Washington
Senior Environmental Specialist
Florida Power and Light Company

Enclosures: 6

Department of Environmental Protection

RECEIVED
JUL 05 2002
BUREAU OF AIR REGULATION

Division of Air Resources Management

Identification of Facility

1. Facility Owner/Company Name: **Florida Power and Light Company**	
2. Site Name: **Fort Myers Plant**	
3. Facility Identification Number: **071002** [ ] Unknown	
4. Facility Location: Street Address or Other Locator: **10650 State Road 80** City: **Fort Myers** County: **Lee** Zip Code: **33905**	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **Kevin Washington, Senior Environmental Specialist**
2. Application Contact Mailing Address: Organization/Firm: **FPL Environmental Services Dept.** Street Address: **700 Universe Blvd.** City: **Juno Beach** State: **FL** Zip Code: **33408**
3. Application Contact Telephone Numbers: Telephone: **(561) 691 - 2877** Fax: **(561) 691 - 7049**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	
2. Permit Number:	
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Initial Title V air operation permit for an existing facility which is classified as a Title V source.

[ ] Initial Title V air operation permit for a facility which, upon start up of one or more newly constructed or modified emissions units addressed in this application, would become classified as a Title V source.

Current construction permit number: ____________________

[ ] Title V air operation permit revision to address one or more newly constructed or modified emissions units addressed in this application.

Current construction permit number: ____________

Operation permit number to be revised: ____________

[ ] Title V air operation permit revision or administrative correction to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application. (Also check Air Construction Permit Application below.)

Operation permit number to be revised/corrected: ____________________

[X] Title V air operation permit revision for reasons other than construction or modification of an emissions unit. Give reason for the revision; e.g., to comply with a new applicable requirement or to request approval of an "Early Reductions" proposal.

Operation permit number to be revised: **0710002-007-AV**

Reason for revision: **Title V Renewal, Current Permit Expires December 31, 2002.**

Air Construction Permit Application

This Application for Air Permit is submitted to obtain: (Check one)

[ ] Air construction permit to construct or modify one or more emissions units.

[ ] Air construction permit to make federally enforceable an assumed restriction on the potential emissions of one or more existing, permitted emissions units.

[ ] Air construction permit for one or more existing, but unpermitted, emissions units.

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official:
   William Reichel, Plant General Manager
2. Owner/Authorized Representative or Responsible Official Mailing Address:
   Organization/Firm: **FPL Fort Myers Plant**
   Street Address: **P.O. Box 430**
   City: **Fort Myers** State: **FL** Zip Code: **33905**
3. Owner/Authorized Representative or Responsible Official Telephone Numbers:
   Telephone: **(941)- 693-4200** Fax: **(941)- 693-4333**
4. Owner/Authorized Representative or Responsible Official Statement:

   I, the undersigned, am the owner or authorized representative(check here [ ], if so) or the responsible official (check here [* **X** *], if so) of the Title V source addressed in this application, whichever is applicable. 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. 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 any permitted emissions unit.*

   William Reichel 6/12/02
   Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name: **Kennard M. Kosky**
   Registration Number: [redacted] 14996
2. Professional Engineer Mailing Address:
   Organization/Firm: **Golder Associates**
   Street Address: **6241 NW 23rd Street, suite 500**
   City: **Gainesville** State: **FL** Zip Code: **32653**
3. Professional Engineer Telephone Numbers:
   Telephone: **(352) 336- 5600** Fax:**(352) 336-6603**

4. 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.

If the purpose of this application is to obtain a Title V source air operation permit (check here [**X** *], 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 schedule is submitted with this application.*

If the purpose of this application is to obtain an air construction permit 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.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision 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.

Signature: [signature] Date: 6/30/02

PFM

(seal)

* Attach any exception to certification statement.

RECEIVED

JUL 05 2002

BUREAU OF AIR REGULATION

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
001	FFSG Unit #1 – Retired 8/31/01 and subsequently dismantled		
002	FFSG Unit #2 – Retired 9/01/01 and subsequently dismantled		
003	Combustion Turbine #1		
004	Combustion Turbine #2		
005	Combustion Turbine #3		
006	Combustion Turbine #4		
007	Combustion Turbine #5		
008	Combustion Turbine #6		
009	Combustion Turbine #7		
010	Combustion Turbine #8		
011	Combustion Turbine #9		
012	Combustion Turbine #10		
013	Combustion Turbine #11		
014	Combustion Turbine #12		
018	Combined Cycle Combustion Turbine Generator 2A with Unfired Heat Recovery Steam Generator		
019	Combined Cycle Combustion Turbine Generator 2B with Unfired Heat Recovery Steam Generator		
020	Combined Cycle Combustion Turbine Generator 2C with Unfired Heat Recovery Steam Generator		
021	Combined Cycle Combustion Turbine Generator 2D with Unfired Heat Recovery Steam Generator		
022	Combined Cycle Combustion Turbine Generator 2E with Unfired Heat Recovery Steam Generator		
023	Combined Cycle Combustion Turbine Generator 2F with Unfired Heat Recovery Steam Generator		
024	6 Direct-Fired Natural Gas Fuel Heaters		
025	Mechanical Draft Cooling Tower		
XXX	Painting of plant equipment and non-halogenated solvent cleaning operations		
XXX	Miscellaneous mobile equipment and internal combustion engines		
XXX	Emergency diesel generator		

Application Processing Fee

Check one: [ ] Attached - Amount: $__________ [X] Not Applicable

Construction/Modification Information

1. Description of Proposed Project or Alterations:
2. Projected or Actual Date of Commencement of Construction:
3. Projected Date of Completion of Construction:

Application Comment

The existing steam generating units (Units 1&2) that burned residual fuel oil (including provisions for used oil) were replaced with 6 advanced combustion turbines burning natural gas. The current configuration is a combined cycle that consists of 6 combustion turbines, and 6 heat recovery steam generators (HRSGs) which provide steam for the existing steam turbines from Units 1&2. The 12 simple cycle combustion turbines which burn #2 diesel oil or on-specification used oil from Florida Power & Light Company operations remain as peaking units

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17** East (km): **422.3** North (km): **2952.9**			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **26 / 41 / 49** Longitude (DD/MM/SS): **81 / 46 / 55**			
3. Governmental Facility Code: **O**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters): **The existing steam generating units (Units 1&2) that burned residual fuel oil (including provisions for used oil) were replaced with 6 advanced combustion turbines burning natural gas. The current configuration is a combined cycle unit that consists of 6 combustion turbines, and 6 heat recovery steam generators (HRSGs) which provide steam for the existing steam turbines from Units 1&2. The 12 simple cycle combustion turbines (GT Units 1-12) which burn #2 diesel oil or on-specification used oil from Florida Power & Light Company operations remain as peaking units**			

Facility Contact

1. Name and Title of Facility Contact: **Mr. Bernie Tibble, Environmental Specialist**		
2. Facility Contact Mailing Address: Organization/Firm: **FPL Fort Myers Plant** Street Address: **PO Box 430** City: **Fort Myers**	State: **FL**	Zip Code: **33905**
3. Facility Contact Telephone Numbers: Telephone: **(941) 693 - 4390**	Fax: **(941) 693 - 4333**	

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [X] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters): **The new combustion turbines are subject to NSPS Subpart GG.**	

List of Applicable Regulations

See Attachment PFMFS_A	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [X] Attached, Document ID:**PFMFS_1.tif** [ ] Not Applicable[ ] Waiver Requested
2. Facility Plot Plan: [X] Attached, Document ID:**PFMFS_2.tif** [ ] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [X] Attached, Document ID: **Attachment No. FS-3** [ ] Not Applicable [ ] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [X] Attached, Document ID:**PFMFS_4.doc** [] Not Applicable[ ] Waiver Requested
5. Fugitive Emissions Identification: [X] Attached, Document ID:**PFMFS_5.doc** [] Not Applicable[ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [ ] Attached, Document ID:________ [X] Not Applicable
7. Supplemental Requirements Comment: **The Emission Units associated with this facility are not subject to CAM (40 part 64) since the emission units do not have a "control device" as defined in Section 64.1. Emission Units 018 through 023 have NO_x CEMs as required by File No. 0710002-008-AC and 40 CFR part 75.** **Note: Emission Units 003 through 014 (12 peaking units) are not "acid rain units".**

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8.	List of Proposed Insignificant Activities: [X] Attached, Document ID: PFM_FW2 [ ] Not Applicable
9.	List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:_ _______ [ ] Equipment/Activities On site but Not Required to be Individually Listed [X] Not Applicable **See PFMFS_9.doc**
10.	Alternative Methods of Operation: [ ] Attached, Document ID:________ [X] Not Applicable
11.	Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [X] Not Applicable
12.	Identification of Additional Applicable Requirements: [X] Attached, Document ID: **PFMFS_12** [ ] Not Applicable
13.	Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:__________________________) [X] Not Applicable
14.	Compliance Report and Plan: [X] Attached, Document ID: **PFMFS_14.doc** [ ] Not Applicable
15.	Compliance Certification (Hard-copy Required): [X] Attached, Document ID: **PFMFS_15.doc** [ ] Not Applicable

[**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 06-01-01

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 06-21-01

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 08-17-00

CHAPTER 62-213, F.A.C.: OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION, effective 04-16-01

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.

CHAPTER 62-296, F.A.C.: STATIONARY SOURCES - EMISSION STANDARDS, effective 03-02-99

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

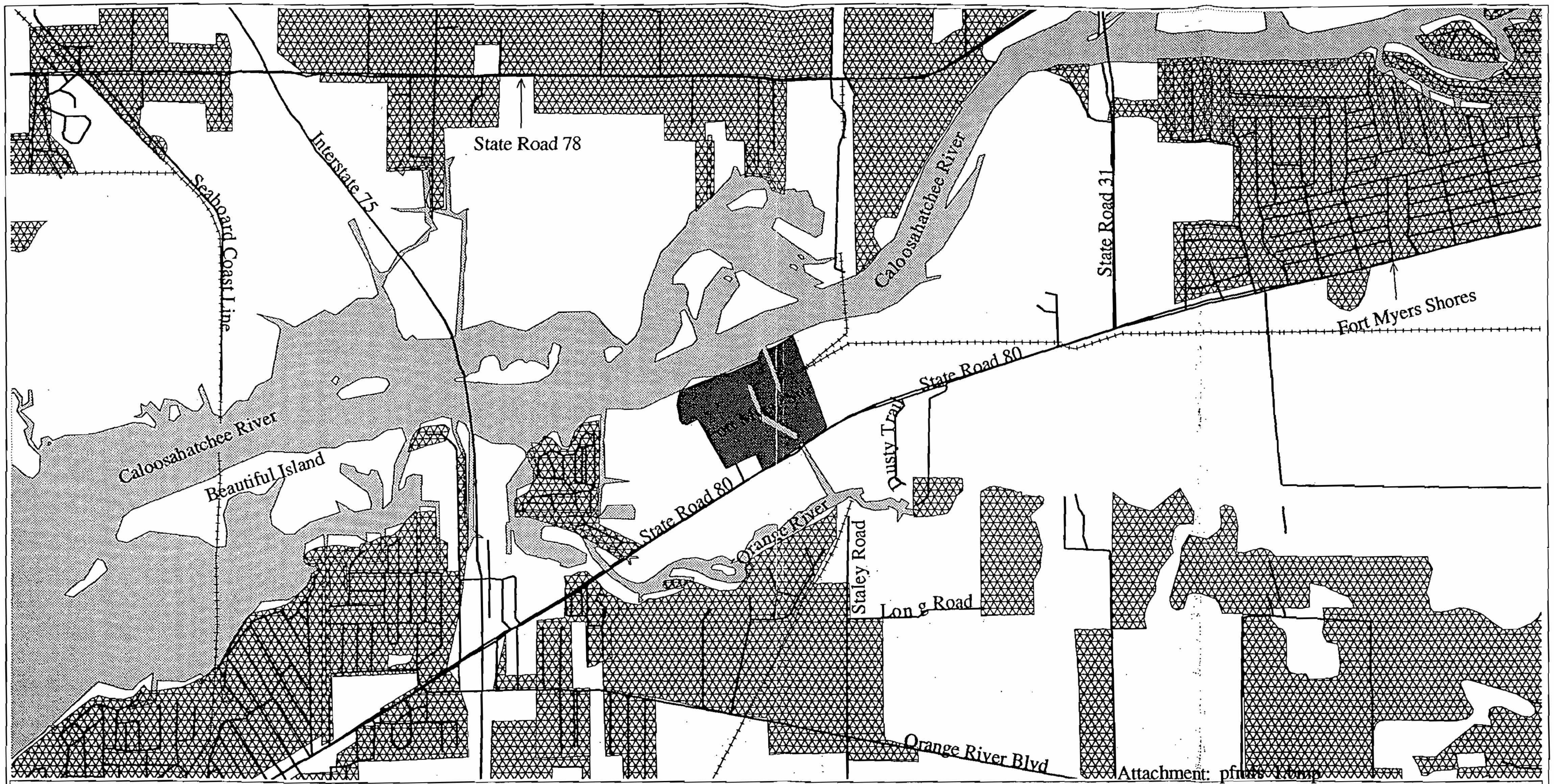
62-296.320(2), F.A.C.: Objectionable Odor Prohibited.

CHAPTER 62-297, F.A.C.: STATIONARY SOURCES - EMISSIONS MONITORING, effective 03-02-99

62-297.310, F.A.C.: General Test Requirements.
62-297.330, F.A.C.: Applicable Test Procedures.
62-297.340, F.A.C.: Frequency of Compliance Tests.
62-297.345, F.A.C.: Stack Sampling Facilities Provided by the Owner of an Emissions Unit.
62-297.350, F.A.C.: Determination of Process Variables.
62-297.570, 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



Fort Myers Plant Area Map
Lee County

Source: Landuse data provided by South Florida Water Management District (1993)

No expressed or implied warranties including, but not limited to the implied warranties of MERCHANTABILITY OF FITNESS FOR A PARTICULAR PURPOSE are made.
The materials contained herein are provided 'as is' and may contain inaccuracies and user is warned to utilize the material's accuracy independently and assumes the risk of any and all loss.

FPL Environmental Affairs

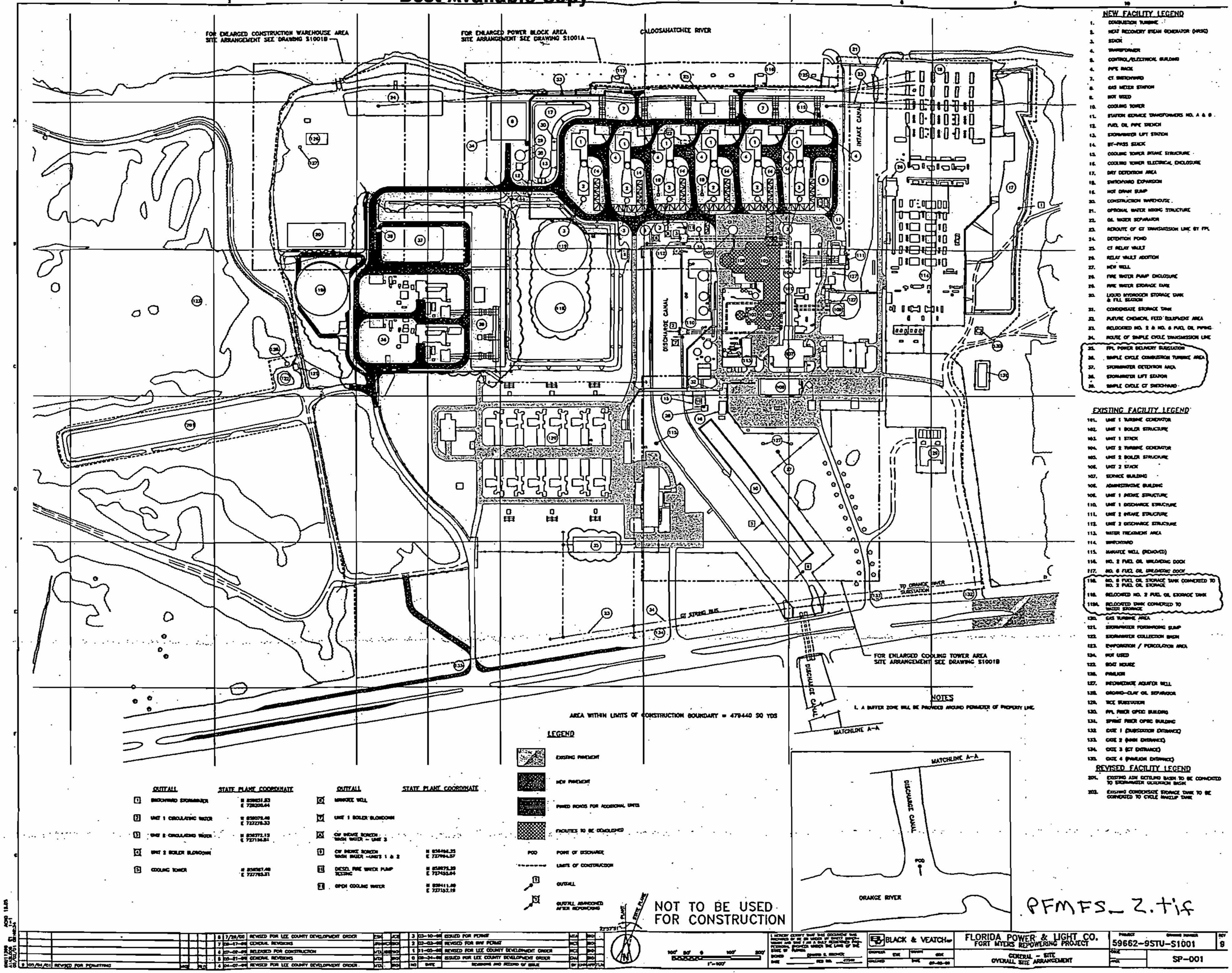
0km 1km 2km
0mi 1mi

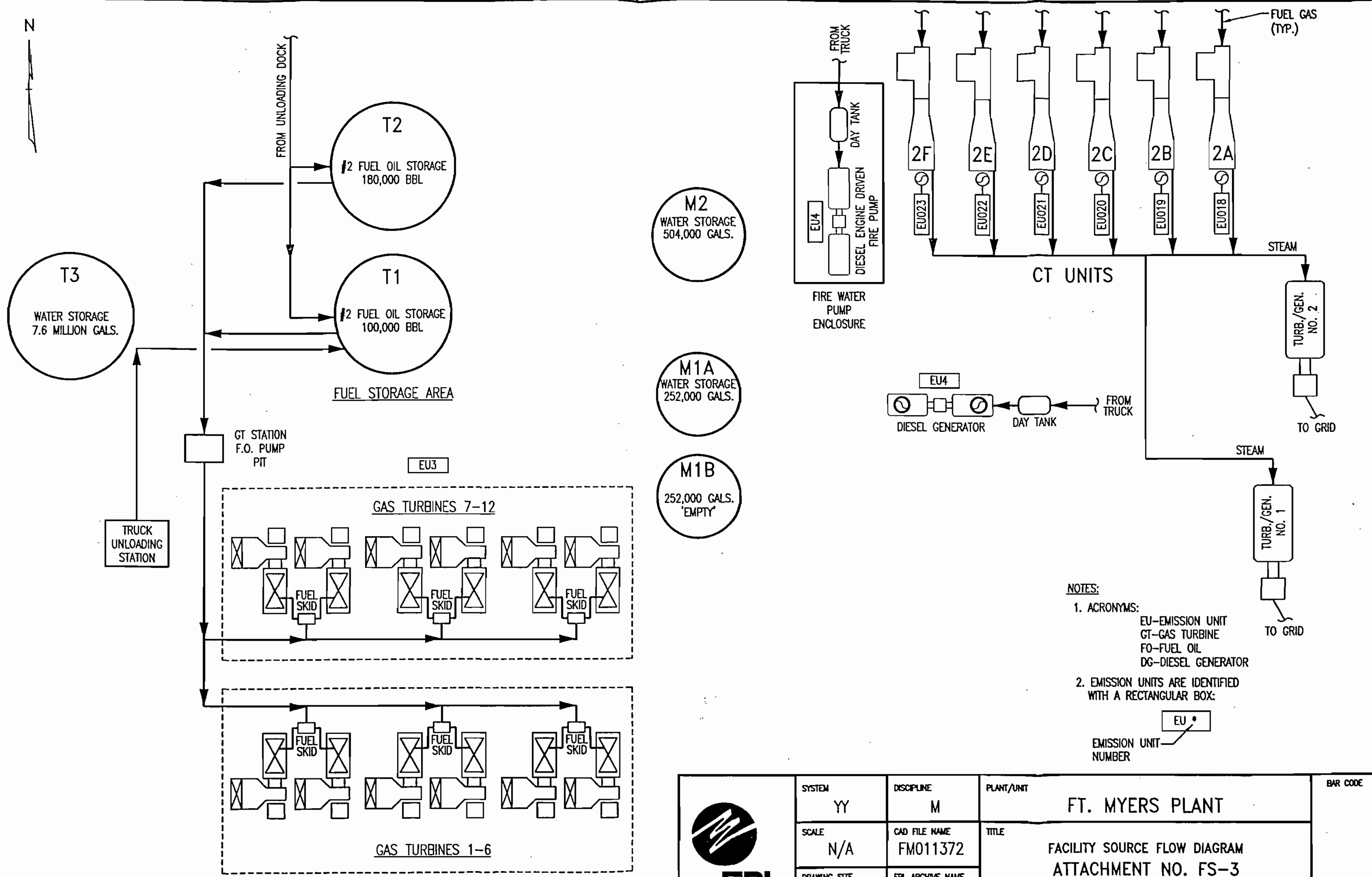
N W E S

- Fort Myers Plant Site
- Water
- Residential Areas
- Major Roads
- Railroads

/export/home/ron/maps/pfm-site.map (8-95)

Best Available Copy





NOTES:

1. ACRONYMS:
   - EU–EMISSION UNIT
   - GT–GAS TURBINE
   - FO–FUEL OIL
   - DG–DIESEL GENERATOR
2. EMISSION UNITS ARE IDENTIFIED WITH A RECTANGULAR BOX:

FPL	SYSTEM YY	DISCIPLINE M	PLANT/UNIT FT. MYERS PLANT	BAR CODE
	SCALE N/A	CAD FILE NAME FM011372	TITLE FACILITY SOURCE FLOW DIAGRAM ATTACHMENT NO. FS-3 TITLE V	
	DRAWING SIZE B(11"X17")	FPL ARCHIVE NAME FM011372		
	DRAWING NUMBER PFM1–M0101–YY		SHEET 1 OF 1	REV 1

REV	DATE	REVISION DESCRIPTION	BY	CH	COR	APR	ORG
1	6/25/02	CAD REDRAWN TO INCORPORATE REPOWER MODIFICATIONS	ELV	SD			PGD
0	8/1/95	ISSUED FOR TITLE V PERMIT	PWB	PWB	CSP	CSP	ETS

WALKDOWN INFORMATION			
AS-BUILT INFORMATION	ORG	BY	DATE

TECHNICAL ACCEPTANCE			
ENGINEERING ORGANIZATION	ORG	BY	DATE

SCALE 3/8" = 1'-0"

SCALE 1/4" = 1'-0"

GSYM/FPGBDR-B 5/93

Attachment PFMFS_4.doc
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. Potential examples of particulate matter include:

- fugitive dust from unpaved roads
- sandblasting abrasive material from plant maintenance activities
- fugitive particulates from the use of bagged chemical products (soda ash, di-, tri- and monosodium phosphate, and other chemicals as needed)

Several precautions were taken to prevent emissions of particulate matter in the *original design* of the facility. These include:

- Paving of roads, parking areas and equipment yards
- Landscaping and planting of vegetation

Operational measures are undertaken at the facility which also minimize particulate emissions, in accordance with 17-296.310 F.A.C.:

- Use of thick poly flaps over the doorways to prevent any sandblasting material from leaving the sandblast facility. The facility also constructs temporary sandblasting enclosures when necessary, in order to perform sandblasting on fixed plant equipment.
- Maintenance of paved areas as needed
- Regular mowing of grass and care of vegetation
- Limiting access to plant property by unnecessary vehicles.
- Bagged chemical products are stored in weather-tight buildings until they are used. Spills of powdered cheical products are cleaned up as soon as practicable.
- Vehicles are restricted to slow speeds on the plant site

Attachment PFMFS_5.doc
Fugitive Emissions Identification

Three pollutants are considered as fugitive emissions at the facility: particulate matter (PM), volatile organic compounds (VOC) and total hazardous air pollutants (HAPs). The fugitive PM emissions are comprised of fugitive dust from unpaved roads, sandblasting, the use of bagged chemical products, and are addressed in the previous attachment (Attachment PFMFS_4.txt). The fugitive VOC emissions are comprised of several sources at the facility site, including breathing and working losses for fuel storage tanks, painting, aerosol can usage, solvent use, etc.

It should be noted that many fugitive emissions at the facility can be classified as insignificant activities (below relevant reporting thresholds), and are therefore not included here. The following examples are relevant to this facility.

Fugitive VOC Emissions

- VOC emissions associated with Fuel Oil Storage Tanks are addressed in the Emission Unit XXX, Unregulated emission units section of this application. The fugitive VOC emissions for the fuel storage tanks at this facility, based on maximum fuel throughput were calculated by the EPA Tanks2 computer model to be 16.18 tons/year.

Fugitive Hazardous Air Pollutants (HAPs) Emissions

- The total HAPS emissions for the diesel generator, and fugitive emissions from the fuel oil storage tanks have been calculated to be above the reporting threshold of 1.0 ton/year.

ATTACHMENT PFM – FW2

FT. MYERS PLANT LIST OF UNREGULATED AND INSIGNIFICANT ACTIVITIES

Following are several pages of unregulated and insignificant activities at the facility. The insignificant activities identified in this application are provided for information only and are identified as examples of, but not limited to, the insignificant activities identified by the Division of Air Resources Management. It is understood that such activities do not have to be included in with the Title V Application. The insignificant activities identified herein are consistent, in terms of amounts of emissions and types, with those activities listed in DARM's previous guidance.

Pursuant to Rule 62-210.300(3)(b)1., notice is herein provided that the emissions units listed below are not subject to a permit issued by the Department of Environmental Protection and are exempt from permitting until a final determination is made under the Title V permitting requirements (Rule 62-213 F.A.C.). These units would not have triggered review under Rules 62-212.400 or 62-212.500 or any new source performance standard listed in Rule 62-204.800 F.A.C..

ATTACHMENT PFM – FW2

FT. MYERS PLANT LIST OF UNREGULATED AND INSIGNIFICANT ACTIVITIES

COMBINED CYCLE UNIT 2 ANCILLARY BUILDINGS/AREAS

Miscellaneous Buildings H.V.A.C.

Control Building: Offices, Kitchen, Toilets

Service Building: Offices, Kitchen, Toilets

Switchyard Building

Collector Yard Building

Steam Turbine Control Building

C.E.M. Building

Water Treatment/Lab

Administration Building

I & C Building

Sanitary Vents/Stacks

Control Building

Service Building

Administration Building

Storage Warehouse

Port-a-Johns

Miscellaneous Buildings Vent/Exhaust Systems

Service Building

Chemical Lab Central

Chemical Lab Remote

R.O. Bldg

R.O. External

Diesel Gen. Bldg

Gas Bottle Storage Bldg

ATTACHMENT PFM – FW2

FT. MYERS PLANT LIST OF UNREGULATED AND INSIGNIFICANT ACTIVITIES

Switchyard Control Bldg

Collector Yard Building

Steam Turbine Control Building

Paint & Lube Oil Storage Bldg

Warehouses

Control Bldg

Chlorination Bldg

I & C Shop

Weld Shop

Administration Bldg

<u>Miscellaneous Maintenance Facilities</u>

Air Compressors

Sandblasting Units

Non-Halogenated Solvent Cleaning Operations

Lawn Maintenance Engine Emissions, Fertilizers

Cleaning, Painting, Welding, Coating Hand Held Tools & Equipment

Products Storage in Sealed Containers

Application of Fungicide; Herbicide & Pesticide

Vacuum Cleaning, Solvent Storage, Office Supplies/Equipment

Miscellaneous Gasoline & Diesel Engine Portable Tools & Equipment

C.E.M. BuildingTesting Equipment

<u>Gas Bottle Storage</u>

Nitrogen, Hydrogen, C02 Cylinders, Cryogenic H2 Storage tank Vent

ATTACHMENT PFM – FW2

FT. MYERS PLANT LIST OF UNREGULATED AND INSIGNIFICANT ACTIVITIES

Unpaved Roads

Fugitive Dust

Sumps

Oily Wastewater Separators

Fuel Oil, Light

Tanker Unloading Dock Area Fugitive Emissions

Centralized Hazardous Waste & Storage Area
Sealed Drums & Containers

Storage Area Asbestos Equipment

GAS TURBINE SITE - ANCILLARY BUILDINGS/AREAS

Miscellaneous Buildings H.V.A.C.
General Electric Control Building

Gas Turbine Service Building

G.T. Battery Rooms

Sanitary Vents/Stacks
General Electric Control Building

Gas Turbine Service Building

Miscellaneous Buildings Vent/Exhaust Systems
Service Building

Maintenance Building

G.T. Building

ATTACHMENT PFM – FW2

FT. MYERS PLANT LIST OF UNREGULATED AND INSIGNIFICANT ACTIVITIES

GAS TURBINE SITE UNITS 1 THRU 12 POWER BLOCK

<u>Fuel Oil#2</u>
Fuel Oil Storage Tanks Vents (180,000 BBL & 100,000 BBL)

G.T. Fuel Skid Relief Valve

<u>Fire Protection</u>
CO_2 Fire Suppression System

COMBINED CYCLE UNIT 2 COMBUSTION TURBINES

<u>CT2A through 2F</u>

Fuel Gas Safety

Fuel Gas Coalescing Filter Vent

Fuel Gas Coalescing Filter Drain Tank

Fuel Gas Direct Fired Heater Exhaust Stack

Fuel Gas Direct Fired Heater Drain

Fuel Gas Direct Fired Heater Safety

Fuel Gas Tube & Shell Heater Safety

Fuel Gas Tube & Shell Heater Gas Side Drain

Fuel Gas Tube & Shell Heater Gas Side Vent

Fuel Gas Tube & Shell Water Side Safety

Fuel Gas Tube & Shell Water Side Safety

Fuel Gas Tube & Shell Water Side Vent

Fuel Gas CT Control Gas Vent

Gas Line Drains

Gas Line Vents

CO2 Fire Suppression system Drain

CO2 Fire Suppression system Vent

CO2 Fire Suppression system discharge points in the CT Building

ATTACHMENT PFM – FW2

FT. MYERS PLANT LIST OF UNREGULATED AND INSIGNIFICANT ACTIVITIES

Water Wash Skid Drain

Water Wash Collection Tank

Water Wash casing drain

PEECC Building HVAC Drain

PEECC Building Floor Drain

Auxiliary Cabinet Explosion diaphragms

Auxiliary Cabinet water Drains

Auxiliary Cabinet Oil Drains

Fogger water skid Drain

Inlet plenum Drain

GEC Building HVAC

GEC Building Floor Drain

COMBINED CYCLE UNIT 2 HEAT RECOVERY STEAM GENERATORS
Primarily steam and water vents/drains

<u>HRSG 2A THROUGH 2F:</u>

High Pressure Drum Safety

High Pressure Drum Vent

High Pressure Drum Drain

High Pressure Intermittent Blowdown

High Pressure Drum Instrumentation Drains

Main Steam Safety

Main Steam Vents

Main Steam Drains

High Pressure Feedwater Drain

High Pressure Economizer Drain

ATTACHMENT PFM – FW2

FT. MYERS PLANT LIST OF UNREGULATED AND INSIGNIFICANT ACTIVITIES

High Pressure Evaporator Drain

Intermediate Pressure Drum Safety

Intermediate Pressure Drum Vent

Intermediate Pressure Drum Drain

Intermediate Pressure Intermittent Blowdown

Intermediate Pressure Instrumentation Drains

Intermediate Pressure Steam Safety

Intermediate Pressure Steam Drain

Intermediate Pressure Steam Vent

Intermediate Pressure Feedwater Drain

Intermediate Pressure Economizer Drain

Intermediate Pressure Evaporator Drain

Cold Reheat Header Safety

Cold Reheat Header Drain

Hot Reheat Header Safety

Hot Reheat Header Vent

Hot Reheat Header Drain

Fuel Gas Feedwater return Drain

Low Pressure Drum Safety

Low Pressure Drum Vent

Low Pressure Drum Drain

Low Pressure Drum Intermittent Blowdown

Low Pressure Instrumentation Drains

Low Pressure Steam Safety

Low Pressure Steam Vent

Low Pressure Steam Drain

ATTACHMENT PFM – FW2

FT. MYERS PLANT LIST OF UNREGULATED AND INSIGNIFICANT ACTIVITIES

Low Pressure Feedwater Drain

Low Pressure Economizer Drain

Low Pressure Evaporator Drain

High Pressure Feedpump Drain

Process Instrumentation Drains

COMBINED CYCLE UNIT 2 COMMON PIPING AREA
Primarily steam and feedwater vent/drains

Main Steam Lines Drains to Drains Tank

Hot Reheat Lines Drains to Drains Tank

Cold Reheat Lines Drains to Drains Tank

Turbine Area Drains Tank Vent

Main Steam Lines Drains to Drains Header

Hot Reheat Lines Drains to Drains Header

Cold Reheat Lines Drains to Drains Header

Low Pressure Lines Drains to Drains Header

HRSG A Drains Header Vent

HRSG A Blowdown Drains Tank Vent

HRSG B Drains Header Vent

HRSG B Blowdown Drains Tank Vent

HRSG C Drains Header Vent

HRSG C Blowdown Drains Tank Vent

HRSG D Drains Header Vent

HRSG D Blowdown Drains Tank Vent

HRSG E Drains Header Vent

HRSG E Blowdown Drains Tank Vent

ATTACHMENT PFM – FW2

FT. MYERS PLANT LIST OF UNREGULATED AND INSIGNIFICANT ACTIVITIES

HRSG F Drains Header Vent

HRSG F Blowdown Drains Tank Vent

HRSG B Blowdown Recovery Tank Vent

HRSG E Blowdown Recovery Tank Vent

Blowdown Recovery Cooler Drains

Blowdown Recovery Process Tank Vent

Blowdown Recovery Process Tank Drain

Blowdown Recovery RO Drains

Blowdown Recovery RO Reject

COMBINED CYCLE UNIT 2 COMMON FEEDWATER SYSTEM
Primarily steam and water vents/drains

Condensate Storage Tank Low Pressure Safeties

Condensate Storage Tank High Pressure Safeties

Condensate Storage Tank Drain

Low Pressure Feedpump A Drain

Low Pressure Feedpump B Drain

Low Pressure Feedpump C Drain

Low Pressure Booster Pump A Drain

Low Pressure Booster Pump B Drain

Low Pressure Booster Pumps discharge Line Drain

Demineralized Water Tank Vent

Demineralized Water Tank Drain

Demineralized Water Feedpump A Drain

Demineralized Water Feedpump B Drain

Fogger Water Feedpump A Drain

ATTACHMENT PFM – FW2

FT. MYERS PLANT LIST OF UNREGULATED AND INSIGNIFICANT ACTIVITIES

Fogger Water Feedpump B Drain

Cycle Makeup Tank Vent

Cycle Makeup Tank Drain

Cycle Makeup Feedpump A Drain

Cycle Makeup Feedpump B Drain

Condenser 1 Reject Line Drain

Condenser 2 Reject Line Drain

COMBINED CYCLE UNIT 2 STEAM TURBINE AREAS
Primarily steam and water vents/drains

STEAM TURBINE 1

Condenser Drain

Water Box Inlet Drain A

Water Box Inlet Drain B

Water Box Outlet Drain A

Water Box Outlet Drain B

Exhaust Hood Rupture Diaphragm A

Exhaust Hood Rupture Diaphragm B

Gland Steam Condenser Drain

Gland Steam Condenser Vent

Steam Jet Air Ejector Vent

Steam Jet Air Ejector Drain

Condenser Vacuum Hogger Vent

Condenser Vacuum Hogger Drain
Low Pressure Vent to Atmosphere

Low Pressure Vent to Atmosphere Drain

Low Pressure Bypass Line Vent

ATTACHMENT PFM – FW2

FT. MYERS PLANT LIST OF UNREGULATED AND INSIGNIFICANT ACTIVITIES

COMBINED CYCLE UNIT 2 STEAM TURBINE AREAS
Primarily steam and water vents/drains

STEAM TURBINE 2

Condenser Drain

Water Box Inlet Drain 1A

Water Box Inlet Drain 1B

Water Box Outlet Drain 1A

Water Box Outlet Drain 1B

Water Box Inlet Drain 2A

Water Box Inlet Drain 2B

Water Box Outlet Drain 2A

Water Box Outlet Drain 2B

Exhaust Hood Rupture Diaphragm 1A

Exhaust Hood Rupture Diaphragm 1B

Exhaust Hood Rupture Diaphragm 2A

Exhaust Hood Rupture Diaphragm 2B

Gland Steam Condenser Drain

Gland Steam Condenser Vent

Steam Jet Air Ejector Vent

Steam Jet Air Ejector Drain

Condenser Vacuum Hogger Pump Vent

Condenser Vacuum Hogger Pump Drain

Attachment PFMFS_9.doc

EQUIPMENT/ACTIVITIES REGULATED UNDER TITLE VI

The Fort Myers facility currently has no equipment containing more than 50 pounds of CFC's. There are several air conditioning and refrigeration units on the plant site, but these contain less than the threshold quantity of CFC's.

Florida Power and Light Company
Fort Myers Plant
Facility ID No.: 0710002
Lee County

Title V Air Operation Permit Revision
FINAL Permit Revision No.: 0710002-007-AV

<u>Permitting Authority:</u>
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

<u>Compliance Authority:</u>
Department of Environmental Protection
South District

2295 Victoria Avenue, Suite 364
Fort Myers, Florida 33901

Telephone: 941/332-6975
Fax: 941/332-6969

Permittee:
Florida Power and Light Company
P.O. Box 430
Fort Myers, Florida 33905

FINAL Permit Revision No.: 0710002-007-AV
Facility ID No.: 0710002
SIC Nos.: 49, 4911
Project: Title V Air Operation Permit Revision

This permit revision is for the incorporation of the new specific conditions of construction permit 0710002-005-AC, which authorized the installation of inlet foggers at the compressor inlet of the twelve simple cycle combustion turbines, and established a limitation on NOx and the hours of operation at the Fort Myers Plant. This facility is located at 10650 State Road 80, Fort Myers, Lee County; UTM Coordinates: Zone 17, 422.3 km East and 2952.9 km North; Latitude: 26° 41' 49" North and Longitude: 81° 46' 55" West.

STATEMENT OF BASIS: This Title V air operation permit revision 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 perform the work or 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 revision.

Referenced attachments made a part of this permit revision:
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix U-1, List of Unregulated Emissions Units and/or Activities
APPENDIX TV-3, TITLE V CONDITIONS (version dated 4/30/99)
APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)
Phase II Acid Rain Application/Compliance Plan received December 6, 1995
Florida Department of Environmental Protection Order dated January 2, 1986

Effective Date: January 1, 1998
Revision Effective Date: October 22, 2000
Renewal Application Due Date: July 5, 2002
Expiration Date: December 31, 2002

Howard L. Rhodes, Director,
Division of Air Resources
Management

HLR/sms/tc

Title V Air Operation Permit Revision
FINAL Permit Revision No.: 0710002-007-AV

Table of Contents

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of two fuel oil fired conventional steam electric generating stations, designated as Units 1 and 2, and 12 simple-cycle gas turbines, designated as Units 3 through 14, by the Florida Power and Light Company. Unit 1 is comprised of a Babcock and Wilcox outdoor-type boiler/steam generator and a Westinghouse outdoor reheat condensing steam turbine which drives a hydrogen-cooled generator with a nameplate rating of 156.3 megawatts. Unit 2 is comprised of a Foster-Wheeler outdoor-type boiler/steam generator and a General Electric outdoor reheat condensing steam turbine which drives a hydrogen-cooled generator with a generator nameplate rating of 402.1 megawatts.

Units 3 through 14 are fuel oil fired combustion turbines manufactured by the General Electric Company, each with a rated gross capacity of 63 megawatts (MW). Foggers were installed at the compressor inlet to each of the twelve combustion turbines during 1999, and initial compliance testing was completed on November 30, 1999. Also included in this permit are miscellaneous unregulated/insignificant emissions units and/or activities.

Based on the initial Title V permit application received June 12, 1996, this facility is a major source of hazardous air pollutants (HAPs).

Subsection B. Summary of Emissions Unit ID Nos. and Brief Descriptions.

E.U. ID No.	Brief Description
-001	Fossil Fuel Fired Steam Generator #1
-002	Fossil Fuel Fired Steam Generator #2
-003	Combustion Turbine #1
-004	Combustion Turbine #2
-005	Combustion Turbine #3
-006	Combustion Turbine #4
-007	Combustion Turbine #5
-008	Combustion Turbine #6
-009	Combustion Turbine #7
-010	Combustion Turbine #8
-011	Combustion Turbine #9
-012	Combustion Turbine #10
-013	Combustion Turbine #11
-014	Combustion Turbine #12

Unregulated Emissions Units and/or Activities

-xxx	Painting of plant equipment and non-halogenated solvent cleaning operations
-xxx	Miscellaneous mobile equipment and internal combustion engines
-xxx	Emergency diesel generator

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, are specifically related to this permitting action.

These documents are provided to the permittee for information purposes only:
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/ID Number Changes

These documents are on file with permitting authority:
Initial Title V Permit Application received June 12, 1996.
Additional Information Request dated April 25, 1997.
Additional Information Response received July 30, 1997.
Information letter from Florida Power & Light received by fax on September 8, 1997.
Information letter from Florida Power & Light received by fax on September 12, 1997.
DRAFT Title V Permit issued September 22, 1997.
Comment letter from Florida Power & Light received October 9, 1997.
Information letter from Florida Power & Light received October 14, 1997.
PROPOSED Title V Permit Determination dated November 6, 1997.
Comment letter from Florida Power & Light received December 1, 1997.
FINAL Title V Permit issued December 31, 1997.
Air construction permit 0710002-005-AC issued July 20, 1999.
Letter from Florida Power & Light received January 12, 2000, requesting a revision to the Title V Permit.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-3, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-3, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided one copy when requested or otherwise appropriate.}

2. Not federally enforceable. General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. The permittee shall not 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. 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 ; 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]

4. 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.]

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. General Pollutant Emission Limiting Standards. Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department.
[Rule 62-296.320(1)(a), F.A.C.]

7. 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.
[Rule 62-296.320(4)(b)1. & 4., F.A.C.]

8. Not federally enforceable. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include the following:

a. In order to perform sandblasting on fixed plant equipment, sandblasting enclosures are constructed and operated as necessary. Thick polyurethane flaps are used over the doorways to prevent any sandblasting material from leaving the sandblast facility.

b. Maintenance of paved areas is performed as needed.

c. Mowing of grass and care of vegetation are done on a regular basis.

d. Access to plant property by unnecessary vehicles is controlled and limited.

e. Bagged chemical products are stored in weather tight buildings until they are used. Spills of powdered chemical products are cleaned up as soon as practical.

f. Vehicles are restricted to slow speeds on the plant site.

[Rule 62-296.320(4)(c)2., F.A.C.; Proposed by applicant in the initial Title V permit application received June 12, 1996.]

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

Department of Environmental Protection
South District
2295 Victoria Avenue, Suite 364
Fort Myers, Florida 33901
Telephone: 941/332-6975
Fax: 941/332-6969

11. 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 & EPCRA Enforcement Branch, Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303
Telephone: 404/562-9155
Fax: 404/562-9163 or 404/562-9164

12. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition No. 51., Appendix TV-3, Title V Conditions.}
[Rule 62-214.420(11), F.A.C.]

Section III. Emissions Units and Conditions.

Subsection A. This section addresses the following emissions units.

E.U. ID No.	Brief Description
-001	Fossil Fuel Fired Steam Generator #1
-002	Fossil Fuel Fired Steam Generator #2

Fossil Fuel Fired Steam Generator #1 is a nominal 156.3 megawatt (electric) steam generator designated as Fort Myers Unit #1. The emission unit is fired on No. 2 or No. 6 fuel oil with a maximum heat input of 1690 MMBtu per hour. Emissions from Unit #1 are uncontrolled. It commenced commercial operation in November, 1958.

Fossil Fuel Fired Steam Generator #2 is a nominal 402.1 megawatt (electric) steam generator designated as Fort Myers Unit #2. The emission unit is fired on No. 2 or No. 6 fuel oil with a maximum heat input of 4000 MMBtu per hour. It commenced commercial operation in July, 1969.

Particulate matter emissions from Unit #2 are controlled by two UOP Aerotec mechanical dust collectors.

Fuel additives such as, but not limited to, magnesium hydroxide are used to enhance combustion and facilitate furnace cleaning, in a manner consistent with Best Operational Practices.

{Permitting note: the emissions units are 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.}

The following specific conditions apply:

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

A.1. <u>Permitted Capacity.</u> The maximum operation heat input rates are as follows:

Unit No.	MMBtu/hr Heat Input	Fuel Type
1	1690	No. 2 or No. 6 Fuel Oil
2	4000	No. 2 or No. 6 Fuel Oil

Methods of heat input calculation are as determined by hourly fuel usage, and the higher heat value of the oil as determined by as-fired fuel analysis.
[Rules 62-4.160(2), 62-210.200 (PTE), and 62-296.405, F.A.C.; AO36-221394; AO36-221396]

A.2. <u>Emissions Unit Operating Rate Limitation After Testing</u>. See Specific Condition **A.24.**
[Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation. Fuels.

a. Startup: The only fuels allowed to be burned are No. 2 fuel oil, No. 6 fuel oil, on-specification used oil from Florida Power and Light Company operations, or propane gas. These fuels may be mixed or burned simultaneously. Used oil containing PCBs above the detectable level cannot be used for startup or shutdown.

b. Normal: The only fuels allowed to be burned are No. 2 fuel oil, No. 6 fuel oil, or on-specification used oil from Florida Power and Light Company operations. These fuels may be mixed or burned simultaneously.

[Rule 62-213.410, F.A.C.; AO36-221394, Specific Condition No. 2; AO36-221396, Specific Condition No. 2]

A.4. Hours of Operation. The emissions units 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.}

A.5. Visible Emissions. Visible emissions shall not exceed 40 percent opacity. Emissions units governed by this visible emissions standard shall compliance test for particulate matter emissions annually.
[Rule 62-296.405(1)(a), F.A.C.; and Order dated January 2, 1986.]

A.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. Visible emissions above 60 percent opacity shall be allowed for not more than four (4), six (6)-minute periods, during the 3-hour period of excess emissions.

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.]

A.7. Particulate Matter. Particulate matter emissions shall not exceed 0.1 pound per million Btu heat input, as measured by applicable compliance methods.
[Rule 62-296.405(1)(b), F.A.C.]

A.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.
[Rule 62-210.700(3), F.A.C.]

A.9. Sulfur Dioxide.
a. Sulfur dioxide emissions when burning liquid fuel shall not exceed 2.75 pounds per million Btu heat input, as measured by applicable compliance methods. Any calculations used to demonstrate compliance shall be based solely on the Btu value and the percent sulfur of the liquid fuel being burned.
b. The fuel oil sulfur content shall not exceed 2.5 percent, by weight, as fired. See Specific Conditions **A.14., A.21., and A.22.**
[Rules 62-213.440, 62-296.405(1)(c)1.j., & 62-297.440, F.A.C.]

A.10. "On-Specification" Used Oil. Only "on-specification" used oil generated by the Florida Power and Light Company in the production and distribution of electricity shall be fired in these emissions units. The total combined quantity allowed to be fired at these emissions units shall not exceed 1,500,000 gallons per calendar year. "On-specification" used oil is defined as each used oil delivery that meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below. Used oil that does not meet all of the following specifications is considered "off-specification" used oil and shall not be fired. See Specific Conditions **A.16., A.31., and A.32.**

CONSTITUENT/PROPERTY*	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flashpoint	100 degrees F minimum
PCBs	less than 50 ppm

* As determined by approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).
[40 CFR 279.11; and AO36-221394, AO36-221396]

Excess Emissions

A.11. 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.]

A.12. 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.]

A.13. 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

A.14. Sulfur Dioxide. **The permittee elected to demonstrate compliance by accepting a liquid fuel sulfur limit that will be verified with a fuel analysis provided by the vendor upon each fuel delivery.** This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device. See Specific Conditions **A.9.**, **A.21.**, and **A.22.**
[Rule 62-296.405(1)(f)1.b., F.A.C.]

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.]

A.16. Compliance with the "on-specification" used oil requirements will be determined from a sample collected from each batch delivered for firing. See Specific Conditions **A.10.**, **A.31.** and **A.32.**
[Rules 62-4.070 and 62-213.440; and, 40 CFR 279]

Continuous Monitoring Requirements

A.17. The Florida Power and Light Company shall operate, calibrate, and maintain a continuous opacity monitoring system. The continuous opacity monitoring system shall be calibrated, operated, span checked, and maintained according to the manufacturer's recommendations.
[Rule 62-210.700, F.A.C.; AO36-221394, Specific Condition No. 9; AO36-221396, Specific Condition No. 9]

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.18. Visible Emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. See Specific Condition **A.19.**
[Rule 62-296.405(1)(e)1., F.A.C.]

A.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.]

A.20. Particulate Matter. The test methods for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F, incorporated by reference in Chapter 62-297, F.A.C. The minimum sample volume shall be 30 dry standard cubic feet. EPA Method 5 may be used with filter temperature no more than 320 degrees Fahrenheit. For EPA Method 17, stack temperature shall be less than 375 degrees Fahrenheit. The owner or operator may use EPA Method 5 to demonstrate compliance. EPA Method 3 (requires Orsat analysis) or 3A shall be used when the oxygen based F-factor is computed according to EPA Method 19 is used in lieu of heat input. Acetone wash shall be used with EPA Method 5 or 17.
[Rules 62-213.440, 62-296.405(1)(e)2., and 62-297.401, F.A.C.]

A.21. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, the permittee elected to demonstrate compliance by accepting a liquid fuel sulfur limit that will be verified with a fuel analysis provided by the vendor upon each fuel delivery at the Boca Grand Fuel Oil Terminal with the following exception: In cases where No. 6 fuel oil is received with a sulfur content exceeding 2.5%, by weight, and blending is required to obtain a fuel mix equal to the applicable percent sulfur limit, an analysis of a fuel sample representative of fuel from the fuel storage tank(s) will be performed prior to loading of barges destined for the Fort Myers Plant to ensure a sulfur content to the permit emission limitation. Reports of percent sulfur content of these analyses will be maintained at the power plant facility for a minimum of 5 (five) years.** See Specific Conditions **A.9., A.14., and A.22.**
[Rules 62-4.070(3), 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.401, F.A.C.; and, AO36-221394 and AO36-221396]

A.22. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest edition. See Specific Conditions **A.9**, **A.14**, and **A.21**.
[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

A.23. 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.24. Operating Rate During Testing. Testing of emissions shall be conducted with each 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.]

A.25. 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.]

A.26. 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.

TABLE 297.310-1
CALIBRATION SCHEDULE

ITEM	MINIMUM CALIBRATION FREQUENCY	REFERENCE INSTRUMENT	TOLERANCE
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent, or thermometric points	+/-2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass thermometer	5 degrees F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5 degrees F
Barometer	Monthly	Hg barometer or NOAA station	+/-1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	+/-0.001" mean of at least three readings Max. deviation between readings .004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, When 5% change observed, Annually 2. One Point: Semiannually	Spirometer or calibrated wet test or dry gas test meter	2%
	3. Check after each test series	Comparison check	5%

(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.27. 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.]

A.28. 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]

A.29. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning only liquid fuel(s) for less than 400 hours per year.
[Rule 62-297.310(7)(a)4., F.A.C.]

A.30. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning only liquid fuel(s) for less than 400 hours per year.
[Rules 62-297.310(7)(a)3. & 5., F.A.C.]

Record keeping and Reporting Requirements

A.31. Records shall be kept of each delivery of "on-specification" used oil with a statement of the origin of the used oil and the quantity delivered/stored for firing. In addition, monthly records shall be kept of the quantity of "on-specification" used oil fired in these emissions units. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. See Specific Conditions **A.10., A.16. and A.32.**
[Rule 62-213.440(1)(b)2.b., F.A.C.; and, 40 CFR 279.61 and 761.20(e)]

A.32. The permittee shall include in the "Annual Operating Report for Air Pollutant Emitting Facility" a summary of the "on-specification" used oil analyses for the calendar year and a statement of the total quantity of "on-specification" used oil fired in Fossil Fuel Fired Steam Generators Nos. 1 and 2 during the calendar year. See Specific Conditions **A.10., A.16. and A.31.**
[Rule 62-213.440(1)(b)2.b., F.A.C.]

A.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.]

A.34. 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)(j), F.A.C.]

A.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.]

Subsection B. This section addresses the following emissions unit(s).

E.U. ID No.	Brief Description
-003	Combustion Turbine #1
-004	Combustion Turbine #2
-005	Combustion Turbine #3
-006	Combustion Turbine #4
-007	Combustion Turbine #5
-008	Combustion Turbine #6
-009	Combustion Turbine #7
-010	Combustion Turbine #8
-011	Combustion Turbine #9
-012	Combustion Turbine #10
-013	Combustion Turbine #11
-014	Combustion Turbine #12

{Permitting notes: These emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. These emissions units are **not** subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines.}

Each unit has a rated gross capacity of 63 MW. The combustion turbines commenced commercial operation in May, 1974. Foggers were installed at the compressor inlet to each of the twelve combustion turbines during 1999, and initial compliance testing was completed on November 30, 1999.

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

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum heat input rate to the combustion turbines shall not exceed 895 MMBtu/hr/unit, at 25 degrees F (or 760 MMBtu/hr/unit, at 59 degrees F). This maximum heat input rate will vary depending on the ambient conditions and the combustion turbine characteristics, as determined by manufacturer's curves corrected for site conditions.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; AO36-223496, Specific Condition No. 1; 0710002-005-AC, Specific Condition No. 20]

B.2. Methods of Operation - Fuels. The only fuels authorized to be burned in these emissions units are No. 2 distillate fuel oil or on-specification used oil from Florida Power and Light Company operations. See Specific Condition **B.6.** These fuels may be mixed or burned simultaneously.
[Rule 62-213.410, F.A.C.; AO36-223496; and, 0710002-003-AO]

B.3.1. Hours of Operation. These emissions units are allowed to operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.; AO36-223496, Specific Condition No. 8]

B.3.2. The twelve foggers may operate up to 6000 hours per year (average 500 hours per unit per year).
[0710002-005-AC, Specific Condition No. 20]

B.4. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **B.11.**
[Rule 62-297.310(2), 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.}

B.5.1. Visible Emissions. Visible emissions from each turbine shall not be equal to or greater than 20 percent opacity.
[Rule 62-296.320(4)(b)1., F.A.C.; and, AO36-223496, Specific Condition No. 3]

B.5.2. Nitrogen Oxides. NO_x emissions shall not exceed 530 lb/hr/unit at 59 degrees F.
[0710002-005-AC, Specific Condition No. 20]

B.6. "On-Specification" Used Oil. Only "on-specification" used oil generated by the Florida Power and Light Company in the production and distribution of electricity shall be fired in these emissions units. The total combined quantity allowed to be fired **at this facility** shall not exceed 1,500,000 gallons per calendar year. "On-specification" used oil is defined as each used oil delivery that meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below. Used oil that does not meet all of the following specifications is considered "off-specification" used oil and shall not be fired. See Specific Conditions **B.15., B.18., and B.19.**

CONSTITUENT/PROPERTY*	ALLOWABLE LEVEL
Arsenic	5 ppm maximum
Cadmium	2 ppm maximum
Chromium	10 ppm maximum
Lead	100 ppm maximum
Total Halogens	1000 ppm maximum
Flashpoint	100 degrees F minimum
PCBs	less than 2 ppm**

* As determined by approved methods specified in EPA Publication SW-846 (Test Methods for Evaluating Solid Waste, Physical/Chemical Methods).
PCBs must be less than **2 ppm for on-specification used oil to be fired in these emissions units.
[40 CFR 279.11; AO36-22346; and, 0710002-003-AO]

Excess Emissions

B.7. Excess emissions from these emissions units 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.]

B.8. 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.9. 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.10.1. Visible Emissions. The test method for visible emissions shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.
[Rules 62-204.800, 62-296.320(4)(b)4.a., and 62-297.401, F.A.C.]

B.10.2. Nitrogen Oxides. The test method for nitrogen oxides shall be EPA method 7 or 7E, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.
[Rules 62-204.800, 62-296.320(4)(b)4.a., and 62-297.401, F.A.C.; and, 0710002-006-AC, Specific Condition No. 10]

B.11. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operating 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 (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.
[Rules 62-297.310(2), F.A.C.]

B.12. Applicable Test Procedures.
(a) Required Sampling Time.
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.
[Rule 62-297.310(4)(a)2.c., F.A.C.]

B.13. 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 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. The following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 100 tons per year or more of any regulated air pollutant, other than lead, lead compounds measured as elemental lead, and acrylonitrile.
See permit limiting standards and applicable test methods as noted in Specific Conditions **B.5., B.6., & B.10.**
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. See Specific Conditions **B.13.(a).a. & b., and B.14.**

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.14.1. Visible Emissions Testing - Annual and Renewal. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning only liquid fuels for less than 400 hours per year. To meet **permit renewal** requirements, the permittee shall conduct visible emissions tests on 3 (three) of the CTs that did not operate more than 400 hours per year on liquid fuels during the previous five year period.
[Rules 62-297.310(7)(a)4. & 8., F.A.C.]

B.14.2. Nitrogen Oxides Testing. Nitrogen oxides emissions shall be determined by a stack test on one representative turbine. Testing shall be performed each federal fiscal year, no later than September 30th, and on a different turbine not previously tested.
[0710002-005-AC, Specific Condition No. 20]

B.15. Compliance with the "on-specification" used oil requirements, **including an analysis for PCBs**, will be determined from a sample collected from each batch delivered for firing. See Specific Conditions **B.6., B.18.,** and **B.19.**
[Rules 62-4.070 and 62-213.440; and, 40 CFR 279]

Recordkeeping and Reporting Requirements

B.16. 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.]

B.17. 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.
[Rule 62-297.310(8), F.A.C.]

B.18. Records shall be kept of each delivery of "on-specification" used oil with a statement of the origin of the used oil and the quantity delivered/stored for firing. In addition, monthly records shall be kept of the quantity of "on-specification" used oil fired in these emissions units. On a quarterly basis, for each quarter during which used oil is burned, a report shall be submitted to the Department's South District office concerning the quantity and analysis of the on-specification used oil burned. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request. See Specific Conditions **B.6.**, **B.15.**, and **B.19.**
[Rule 62-213.440(1)(b)2.b., F.A.C.; 40 CFR 279.61 and 761.20(e); and, AO36-223496]

B.19. The permittee shall include in the "Annual Operating Report for Air Pollutant Emitting Facility" a summary of the "on-specification" used oil analyses for the calendar year and a statement of the total quantity of "on-specification" used oil fired in Combustion Turbines 1 to 12 during the calendar year. See Specific Conditions **B.6.**, **B.15.**, and **B.18.**
[Rule 62-213.440(1)(b)2.b., F.A.C.]

Section IV. This section is the Acid Rain Part.

Operated by: Florida Power and Light Company
ORIS code: 612
Subsection A. This subsection addresses Acid Rain, Phase II.

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

E.U. ID No.	EPA ID	Description
-001	PFM1	Fossil Fuel Fired Steam Generator #1
-002	PFM2	Fossil Fuel Fired Steam Generator #2

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 units must comply with the standard requirements and special provisions set forth in the application listed below:
a. DEP Form No. 62-210.900(1)(a) (effective July 1, 1995) signed December 4, 1995, and received December 6, 1995.
[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

2. Sulfur dioxide (SO2) allowance allocations for each Acid Rain unit are as follows:

E.U. ID No.	EPA ID	Year	2000	2001	2002
-001	**PFM1**	**SO2 allowances, under Table 2 of 40 CFR 73**	3188*	3188*	3188*
-002	**PFM2**	**SO2 allowances, under Table 2 of 40 CFR 73**	9457*	9457*	9457*

*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 of 40 CFR 73.

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.]

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, Fast-Track Revisions of Acid Rain Parts.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

5. Where an applicable requirement of the Act is more stringent than an applicable requirement of the 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.]

6. Comments, notes, and justifications: None.

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

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, are exempt from the permitting requirements of Chapters 62-210 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 Rule 62-210.300(3)(a), 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 Rule 62.210.300(3)(a), 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	Gas metering area relief valves
2	Hydrazine mixing tank and relief valves
3	Fuel oil storage tanks and related equipment
4	Lube oil tank vents and extraction vents
5	Oil/water separators and related equipment
6	Evaporation of Boiler Chemical Cleaning Waste

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

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 Activities
-xxx	Painting of plant equipment and non-halogenated solvent cleaning operations
-xxx	Miscellaneous mobile equipment and internal combustion engines
-xxx	Emergency diesel generator

Attachment PFMFS_14.doc
Ft. Myers Plant
Compliance Report and Plan

The facility and emissions units identified in this application are in compliance with the Applicable Requirements identified in Sections II.B. and III.D. of the application form and attachments referenced in Section III.L. 12 (if included). Compliance is certified as of the date this application is submitted to the Florida Department of Environmental Regulation as required in Rule 62-213.420(1)(a) F.A.C.

Department of Environmental Protection

Division of Air Resources Management

STATEMENT OF COMPLIANCE - TITLE V SOURCE

Facility Owner/Company Name: FLORIDA POWER & LIGHT COMPANY

Site Name: Fort Myers Plant County: Lee

Title V Air Operation Permit No.: 0710002-007-AV ORIS CODE # 000612

REPORTING PERIOD	REPORT DEADLINE*
JANUARY 1 through DECEMBER 31 of 2001 (year)	MARCH 1, 2002

*See Rule 62-213.440(3)(a)2, F.A.C.

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

____ **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.

X **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:
*** SEE ATTACHMENTS**

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. For each item of noncompliance, the following information is included:

1. Emissions unit identification number.
2. Specific permit condition number.
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.

STATEMENT OF COMPLIANCE - TITLE V SOURCE

RESPONSIBLE OFFICIAL CERTIFICATION

I, the undersigned, am the responsible official as defined in Chapter 62-210.200, F.A.C., 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.

(Signature of Title V Source Responsible Official) 2/4/02 *(Date)*

Name: W. M. Reichel Title: **PLANT GENERAL MANAGER**

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.

(Signature of Acid Rain Source Designated Representative) 2-26-02 *(Date)*

Name: **DAVID W. KNUTSON** Title: **DESIGNATED REPRESENTATIVE**

{Note: Attachments, if required, are created by the responsible official or the designated representative, as appropriate, and should consist of the information specified and any supporting records. Additional information may also be attached by the 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. EPA (U.S. EPA Region 4, Air and EPCRA Enforcement Branch, 61 Forsyth Street, Atlanta GA 30303).}

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

[X] 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. Regulated or Unregulated Emissions Unit? (Check one)

[X] 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.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Combustion Turbines 2A Through 2F

4. Emissions Unit Identification Number: [ ] No ID
ID: 018-023 [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	OCTOBER 2000	49	[X]

9. Emissions Unit Comment: (Limit to 500 Characters)
The emission units are General Electric (GE) Frame 7FA Advanced Combustion Turbines. The units will fire only natural gas and can be operated in simple cycle and combined cycle modes. Each CT has inlet foggers.
Nameplate ratings, heat input, emissions, etc. are listed per each Combustion Turbine. Photos of the new units are available in Attachment PFMU1_A9.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Dry Low NO_x Combustors**
2. Control Device or Method Code(s): **25**

Emissions Unit Details

1. Package Unit: Manufacturer: **General Electric**	Model Number: **7FA**
2. Generator Nameplate Rating: **182**	MW
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		**1,760**	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	**8,760**	hours/year

6. Operating Capacity/Schedule Comment (limit to 200 characters):

Maximum heat input and rating at turbine inlet temperature of 59 degrees F and 60% relative humidity.

Heat input as High Heating Value (LHV).

Generator Nameplate Rating = 182.1 MW

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment PFMU1_C	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See Figure 2-3**	2. Emission Point Type Code: **3**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Units can exhaust through a simple cycle by-pass stack and HRSG stack**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **125 (98)** feet	7. Exit Diameter: **19 (22)** feet
8. Exit Temperature: **220 (1096)** °F	9. Actual Volumetric Flow Rate: **1,196,162** acfm	10. Water Vapor: **7.6** %

11. Maximum Dry Standard Flow Rate: **858,197** dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: **17** East (km): **422.3** North (km): **2953.03**	
14. Emission Point Comment (limit to 200 characters): **Stack conditions are for combined cycle operation and turbine inlet of 35 degrees F.** **During simple cycle operation, the by-pass stack conditions are noted in parentheses above.**	

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Internal Combustion Engines – Electric Generation – Natural Gas - Turbine**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.91**	5. Maximum Annual Rate: **16,722**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **923**
10. Segment Comment (limit to 200 characters): **Maximum and Annual based on 59 degree F turbine inlet.** **Million BTU/SCC as LHV.**		

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			**NS**
SO_2			**EL**
NO_x	**025**		**EL**
CO			**EL**
VOC			**EL**
PM10			**NS**

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **10** lb/hour **43.8** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **10 lb/hr** Reference: **GE, 1998; Black & Veach 1998**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PFMU1_G8.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on maximum provided by manufacturer with provision for margin.**	

Allowable Emissions Allowable Emissions _1_ of _1_

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **10** lb/hour **43.8** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% Opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See FDEP File No. 0710002-004-AC.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **5.1** lb/hour **22.5** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1 grain S/100cf** Reference: **Golder, 1998**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PFMU1_G8.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr and ton/year at 35 degree F turbine inlet temperature.**	

Allowable Emissions Allowable Emissions __1__ of __1__

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units:	4. Equivalent Allowable Emissions: **5.1** lb/hour **22.5** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel sampling; vendor sampling pipeline quality natural gas.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Requested Allowable Emissions and Units = pipeline quality natural gas. Allowable based on typical maximum fuel sulfur content. See FDEP File No. 0710002-004-AC.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **68** lb/hour **297.8** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **9ppmvd @ 15% O_2** Reference: **FDEP File No. 071002-008-AC**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PFMU1_G8.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr and tons/year at 35 degree F turbine inlet temperature. Based on data provided by manufacturer with provision for margin.**	

Allowable Emissions Allowable Emissions __1__ of __1__

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **9 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **68** lb/hour **297.8** tons/year
5. Method of Compliance (limit to 60 characters): **40 CFR Part 75 CEM**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emissions are a 30-day rolling average.** **See FDEP File No. 0710002-004-AC.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **44.9** lb/hour **196.6** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **12 ppmvd** Reference: **FDEP File No. 071002-008-AC**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PFMU1_G8.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr and tons/year at 35 degree F turbine inlet temperature. Based on data provided by manufacturer with provision for margin.**	

Allowable Emissions Allowable Emissions _1_ of _1_

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **12 ppmvd**	4. Equivalent Allowable Emissions: **44.9** lb/hour **196.6** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; Initial Compliance Test only**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See FDEP File No. 0710002-004-AC.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **3** lb/hour **13.1** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **1.4 ppmvd** Reference: **FDEP File No. 0710002-004-AC**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PFMU1_G8.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr and tons/year at 35 degree F turbine inlet temperature. Emissions as methane and exclusive of background.**	

Allowable Emissions Allowable Emissions _1_ of _1_

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.4 ppmvd**	4. Equivalent Allowable Emissions: **3** lb/hour **13.1** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 25A; Initial Compliance Test only**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See FDEP File No. 0710002-004-AC.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM10**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **10** lb/hour **43.8** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **10 lb/hr** Reference: **GE, 1998; Black & Veach 1998**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **See Attachment PFMU1_G8.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on maximum provided by manufacturer with provision for margin.**	

Allowable Emissions Allowable Emissions _1_ of _1_

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **10% Opacity**	4. Equivalent Allowable Emissions: **10** lb/hour **43.8** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test < 10% Opacity**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See FDEP File No. 071002-008-AC.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test - EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters):	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)

Continuous Monitoring System: Continuous Monitor 1 of 1

1. Parameter Code: **EM**	2. Pollutant(s): **NO_x**
3. CMS Requirement: [X] Rule [ ] Other	

4. Monitor Information:
Manufacturer: **NO_x = Thermo Environmental Instruments; O_2 = Servomex**
Model Number: **NO_x = 42C; O_2 = 1400**
Serial Number:

	NO_x	O_2
2A=	**42CHL-66125-351**	**01420C/1302**
2B=	**42CHL-66427-352**	**01420C/1304**
2C=	**42CHL-66490-352**	**01420C/1402**
2D=	**42CHL-66131-351**	**01420C/1403**
2E=	**42CHL-65868-350**	**01420C/1466**
2F=	**42CHL-69215-362**	**01420C/1444**

5. Installation Date: **01 SEP 2000 (2A) THROUGH 01 MAR 2001 (2F)**	6. Performance Specification Test Date: **2A= 10/11/2000 2B= 11/08/2000 2C= 12/12/2000 2D= 04/12/2001 2E= 04/03/2001 2F= 05/31/2001**

7. Continuous Monitor Comment (limit to 200 characters):

CEMs meet requirements of 40 CFR Part 75

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [**X**] Rule [ ] Other
3. Requested 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 (limit to 200 characters): **FDEP Rule 62-210.700(1). Allowed for 2 hours (120 minutes) per 24 hours for start-up, shutdown and malfunction**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units 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:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

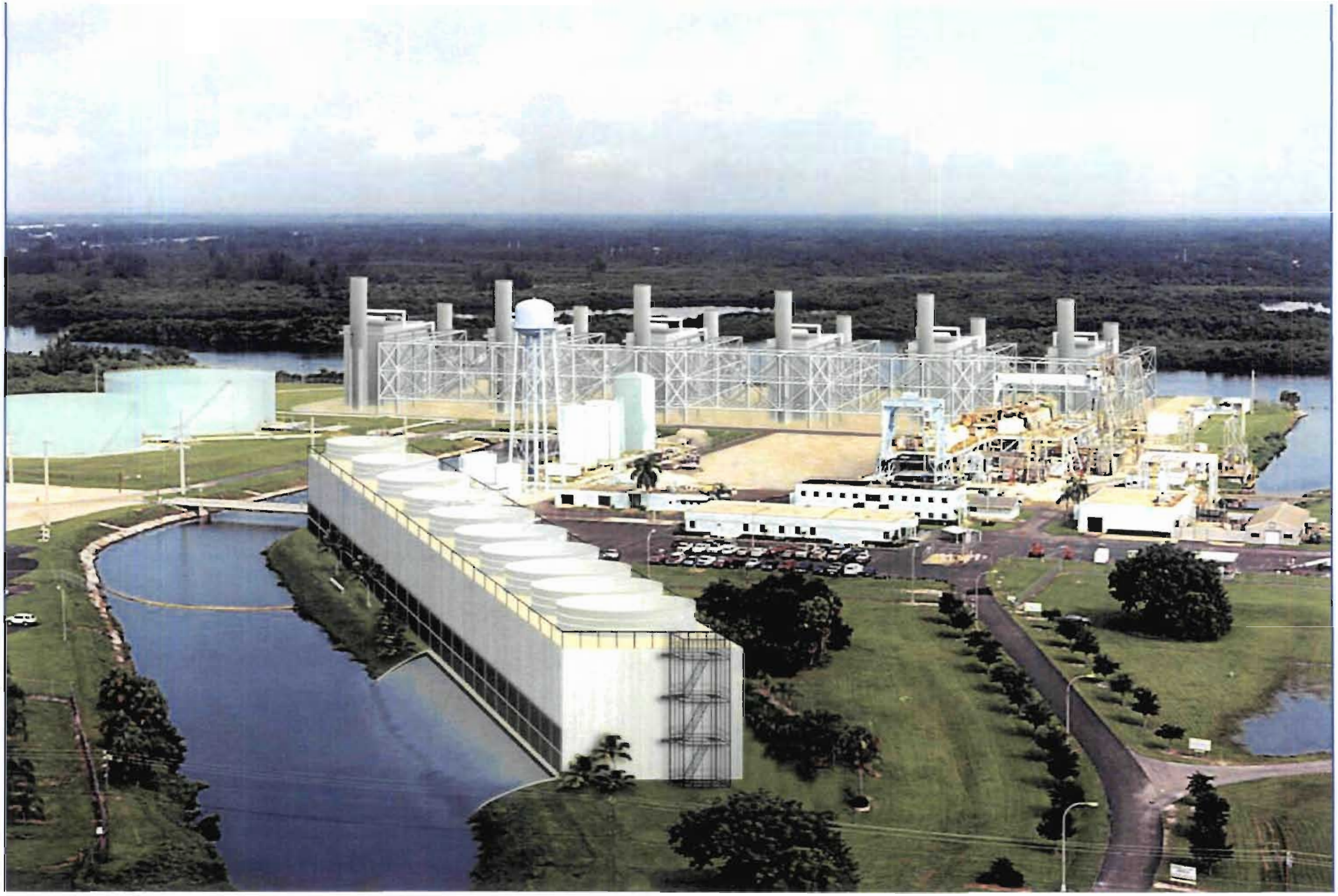
J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: **Figure 2-2** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: **PFMU1_2** [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: **GER-3568F** [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: **PFMCT2Abypassstack and PFMCT2A-2Fstack** [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [X] Attached, Document ID: **PFMU1_5** [ ] Previously submitted, Date:__________ [ ] Not Applicable
6. Procedures for Startup and Shutdown [X] Attached, Document ID: **Administrative-010** [ ] Not Applicable
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID:________ [X] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [X] Attached, Document ID: **PFMCT2A-2F_11.doc** [ ] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [X] Not Applicable
13. Identification of Additional Applicable Requirements [X] Attached, Document ID: **PFMU1_13** [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [X] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [X] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: **PFMU1_15** [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable



ATTACHMENT PFMU1_C

Applicable Requirements Listing

EMISSION UNIT ID: Combustion Turbines 2A – 2F

FDEP Rules:

Air Pollution Control-General Provisions:

62-204.800(7)(b)37. (State Only)	NSPS Subpart GG
62-204.800(7)(c) (State Only)	NSPS authority
62-204.800(7)(d)(State Only)	NSPS General Provisions
62-204.800(12) (State Only)	Acid Rain Program
62-204.800(13) (State Only)	Allowances
62-204.800(14) (State Only)	Acid Rain Program Monitoring
62-204.800(16) (State Only)	Excess Emissions (Potentially applicable over term of permit)

Stationary Sources-General:

62-210.650	Circumvention; EUs with control device
62-210.700(1)	Excess Emissions;
62-210.700(4)	Excess Emissions; poor maintenance
62-210.700(6)	Excess Emissions; notification

Acid Rain:

62-214.300	All Acid Rain Units (Applicability)
62-214.320	All Acid Rain Units (Application Shield)
62-214.330(1)(a)	Compliance Options (if 214.430)
62-214.340	Exemptions (retired units)
62-214.350(2);(3);(5);(6)	All Acid Rain Units (Certification)
62-214.370	All Acid Rain Units (Revisions; correction; potentially applicable if a need arises)
62-214.430	All Acid Rain Units (Compliance Options-if required)

Stationary Sources-Emission Standards:

62-296.320(4)(b)(State Only)	CTs/Diesel Units

Stationary Sources-Emission Monitoring (where stack test is required):

62-297.310(1)	All Units (Test Runs-Mass Emission)
62-297.310(2)	All Units (Operating Rate)
62-297.310(3)	All Units (Calculation of Emission)
62-297.310(4)	All Units (Applicable Test Procedures)
62-297.310(5)	All Units (Determination of Process Variables)
62-297.310(6)(a)	All Units (Permanent Test Facilities-general)
62-297.310(6)(c)	All Units (Sampling Ports)
62-297.310(6)(d)	All Units (Work Platforms)
62-297.310(6)(e)	All Units (Access)
62-297.310(6)(f)	All Units (Electrical Power)
62-297.310(6)(g)	All Units (Equipment Support)
62-297.310(7)(a)1.	Applies mainly to CTs/Diesels

62-297.310(7)(a)3.	Permit Renewal Test Required
62-297.310(7)(a)4.	Annual Test
62-297.310(7)(a)5.	PM exemption if <400 hrs/yr
62-297.310(7)(a)8.	VE Compliance Test if > 400 hrs/yr
62-297.310(7)(a)9.	FDEP Notification - 15 days
62-297.310(7)(c)	Waiver of Compliance Tests (Fuel Sampling)
62-297.310(8)	Test Reports

Federal Rules:

NSPS Subpart GG:

40 CFR 60.332(a)(1)	NO_x for Electric Utility CTs
40 CFR 60.332(a)(3)	NO_x for Electric Utility CTs
40 CFR 60.333	SO_2 limits
40 CFR 60.334	Monitoring of Operations (Custom Monitoring for Gas)
40 CFR 60.335	Test Methods

NSPS General Requirements:

40 CFR 60.7(a)(1)	Notification of Construction
40 CFR 60.7(a)(3)	Notification of Actual Start-Up
40 CFR 60.7(a)(4)	Notification and Recordkeeping (Physical/Operational Cycle)
40 CFR 60.7(a)(5)	Notification of CEM Demonstration
40 CFR 60.7(b)	Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(c)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(d)	Notification and Recordkeeping (startup/shutdown/malfunction)
40 CFR 60.7(f)	Recordkeeping (maintain records-2 yrs)
40 CFR 60.8(a)	Performance Test Requirements
40 CFR 60.8(b)	Performance Test Requirements
40 CFR 60.8(c)	Performance Tests (representative conditions)
40 CFR 60.8(d)	Performance Test Notification
40 CFR 60.8(e)	Provide Stack Sampling Facilities
40 CFR 60.8(f)	Test Runs
40 CFR 60.11(a)	Compliance (ref. S. 60.8 or Subpart; other than opacity)
40 CFR 60.11(b)	Compliance (opacity determined EPA Method 9)
40 CFR 60.11(c)	Compliance (opacity; excludes startup/shutdown/malfunction)
40 CFR 60.11(d)	Compliance (maintain air pollution control equip.)
40 CFR 60.11(e)(2)	Compliance (opacity; ref. S. 60.8)
40 CFR 60.12	Circumvention
40 CFR 60.13(a)	Monitoring (Appendix B; Appendix F)
40 CFR 60.13(d)(1)	Monitoring (CEMS; span, drift, etc.)
40 CFR 60.13(e)	Monitoring (frequency of operation)
40 CFR 60.13(f)	Monitoring (frequency of operation)

Acid Rain-Permits:

40 CFR 72.9(a)	Permit Requirements
40 CFR 72.9(b)	Monitoring Requirements
40 CFR 72.9(c)(1)	SO_2 Allowances-hold allowances
40 CFR 72.9(c)(2)	SO_2 Allowances-violation
40 CFR 72.9(c)(3)(iv)	SO_2 Allowances-Phase II Units
40 CFR 72.9(c)(4)	SO_2 Allowances-allowances held in ATS

40 CFR 72.9(c)(5)	SO_2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(e)	Excess Emission Requirements
40 CFR 72.9(f)	Recordkeeping and Reporting
40 CFR 72.9(g)	Liability
40 CFR 72.20(a)	Designated Representative; required
40 CFR 72.20(b)	Designated Representative; legally binding
40 CFR 72.20(c)	Designated Representative; certification requirements
40 CFR 72.21	Submissions
40 CFR 72.22	Alternate Designated Representative
40 CFR 72.23	Changing representatives; owners
40 CFR 72.24	Certificate of representation
40 CFR 72.30(a)	Requirements to Apply
40 CFR 72.30(b)(2)	Requirements to Apply (Phase II-Complete)
40 CFR 72.30(c)	Requirements to Apply (reapply before expiration)
40 CFR 72.30(d)	Requirements to Apply (submittal requirements)
40 CFR 72.31	Information Requirements; Acid Rain Applications
40 CFR 72.32	Permit Application Shield
40 CFR 72.33(b)	Dispatch System ID;unit/system ID
40 CFR 72.33(c)	Dispatch System ID;ID requirements
40 CFR 72.33(d)	Dispatch System ID;ID change
40 CFR 72.40(a)	General; compliance plan
40 CFR 72.40(b)	General; multi-unit compliance options
40 CFR 72.40(d)	General; termination of compliance options
40 CFR 72.51	Permit Shield
40 CFR 72.90	Annual Compliance Certification
Allowances:	
40 CFR 73.33(a),(c)	Authorized account representative
40 CFR 73.35(c)(1)	Compliance: ID of allowances by serial number
Monitoring Part 75:	
40 CFR 75.4	Compliance Dates;
40 CFR 75.5	Prohibitions
40 CFR 75.10(a)(1)	Primary Measurement; SO_2;
40 CFR 75.10(a)(2)	Primary Measurement; NO_x;
40 CFR 75.10(a)(3)(iii)	Primary Measurement; CO_2; O_2 monitor
40 CFR 75.10(b)	Primary Measurement; Performance Requirements
40 CFR 75.10(c)	Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(f)	Primary Measurement; Minimum Measurement
40 CFR 75.10(g)	Primary Measurement; Minimum Recording
40 CFR 75.11(d)	SO_2 Monitoring; Gas- and Oil-fired units
40 CFR 75.11(e)	SO_2 Monitoring; Gaseous firing
40 CFR 75.12(a)	NO_x Monitoring; Coal; Non-peaking oil/gas units
40 CFR 75.12(c)	NO_x Monitoring; Determination of NO_x emission rate; Appendix F
40 CFR 75.13(b)	CO_2 Monitoring; Appendix G
40 CFR 75.13(c)	CO_2 Monitoring; Appendix F
40 CFR 75.14(c)	Opacity Monitoring; Gas units; exemption
40 CFR 75.20(a)	Initial Certification Approval Process; Loss of Certification
40 CFR 75.20(b)	Recertification Procedures (if recertification necessary)
40 CFR 75.20(c)	Certification Procedures (if recertification necessary)

40 CFR 75.21(a)	QA/QC; CEMS; Appendix B (Suspended 7/17/95-12/31/96)
40 CFR 75.21(c)	QA/QC; Calibration Gases
40 CFR 75.21(d)	QA/QC; Notification of RATA
40 CFR 75.21(e)	QA/QC; Audits
40 CFR 75.22	Reference Methods
40 CFR 75.24	Out-of-Control Periods; CEMS
40 CFR 75.30(a)(3)	General Missing Data Procedures; NO_x
40 CFR 75.30(a)(4)	General Missing Data Procedures; CO_2
40 CFR 75.30(d)	General Missing Data Procedures; SO_2
40 CFR 75.31	Initial Missing Data Procedures (new/re-certified CMS)
40 CFR 75.32	Monitoring Data Availability for Missing Data
40 CFR 75.33	Standard Missing Data Procedures
40 CFR 75.36	Missing Data for Heat Input
40 CFR 75.53	Monitoring Plan; revisions
40 CFR 75.57(a)	Recordkeeping Requirements for Affected Sources
40 CFR 75.57(b)	Operating Parameter Record Provisions
40 CFR 75.57(d)	NO_x Emission Record Provisions
40 CFR 75.57(e)	CO_2 Emission Record Provisions
40 CFR 75.57(h)	Missing Data Records
40 CFR 75.58(c)	Specific SO_2 Emission Record Provisions
40 CFR 75.58(e)	Specific SO_2 Emission Record Provisions
40 CFR 75.59	Certification; QA/QC Provisions
40 CFR 75.60	Reporting Requirements-General
40 CFR 75.61	Reporting Requirements-Notification cert/recertification
40 CFR 75.62	Reporting Requirements-Monitoring Plan
40 CFR 75.63	Reporting Requirements-Certification/Recertification
40 CFR 75.64(a)	Reporting Requirements-Quarterly reports; submission
40 CFR 75.64(b)	Reporting Requirements-Quarterly reports; DR statement
40 CFR 75.64(c)	Rep. Req.; Quarterly reports; Compliance Certification
40 CFR 75.64(d)	Rep. Req.; Quarterly reports; Electronic format
40 CFR 75.64(f)	Method of Submission
40 CFR 75.64(g)	Submission Requirements
40 CFR 75.66	Petitions to the Administrator (if required)
Appendix A	Specifications and Test Procedures
Appendix B	QA/QC Procedures
Appendix C.	Missing Data Estimation Procedures
Appendix D	Optional SO_2; Oil-/gas-fired units
Appendix F	Conversion Procedures

Acid Rain Program-Excess Emissions:

40 CFR 77.3	Offset Plans
40 CFR 77.5(b)	Deductions of Allowances
40 CFR 77.6	Excess Emissions Penalties (SO_2)

Attachment PFMU1_G8. Maximum Emissions for Criteria Pollutants for FPL Fort Myers Repowering Project
GE Frame 7FA, Dry Low NOx Combustor, Natural Gas, Base Load

Parameter	Ambient Temperature 35 °F	59 °F	75 °F	95 °F
Hours of Operation	8,760	8,760	8,760	8,760
Particulate (lb/hr) = Emission rate (lb/hr) from manufacturer				
Basis (excludes H_2SO_4), lb/hr	10	10	10	10
Emission rate (lb/hr)- provided	10.0	10.0	10.0	10.0
(TPY)	43.8	43.8	43.8	43.8
Sulfur Dioxide (lb/hr) = Natural gas (cf/hr) x sulfur content(gr/100 cf) x 1 lb/7000 gr x (lb SO_2 /lb S) /100				
Fuel density (lb/ft^3)	0.0448	0.0448	0.0448	0.0448
Fuel use (cf/hr)	1,799,746	1,721,319	1,651,132	1,557,388
Sulfur content (grains/ 100 cf)	1	1	1	1
lb SO_2 /lb S (64/32)	2	2	2	2
Emission rate (lb/hr)	5.1	4.9	4.7	4.4
(TPY)	22.52	21.54	20.66	19.49
Nitrogen Oxides (lb/hr) = NOx(ppm) x {[20.9 x (1 - Moisture(%)/100)] - Oxygen(%)} x 2116.8 x Volume flow (acfm) x 46 (mole. wgt NOx) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 5.9 x 1,000,000 (adj. for ppm)]				
Basis, ppmvd @15% O_2	9	9	9	9
Moisture (%)	7.6	8.42	9.07	9.95
Oxygen (%)	12.61	12.45	12.37	12.28
Turbine Flow (acfm)	2,737,101	2,656,962	2,593,227	2,507,258
Turbine Exhaust Temperature (°F)	1,096	1,118	1,130	1,147
Emission rate (lb/hr)	68.0	65.0	62.4	58.9
(TPY)	297.8	284.6	273.4	257.8
Carbon Monoxide (lb/hr) = CO(ppm) x [1 - Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 28 (mole. wgt CO) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	12	12	12	12
Moisture (%)	7.6	8.42	9.07	9.95
Turbine Flow (acfm)	2,737,101	2,656,962	2,593,227	2,507,258
Turbine Exhaust Temperature (°F)	1,096	1,118	1,130	1,147
Emission rate (lb/hr)	44.9	42.6	41.0	38.8
(TPY)	196.6	186.5	179.4	170.0
VOCs (lb/hr) = VOC(ppmvd) x [1-Moisture(%)/100] x 2116.8 lb/ft2 x Volume flow (acfm) x 16 (mole. wgt as methane) x 60 min/hr / [1545 x (CT temp.(°F) + 460°F) x 1,000,000 (adj. for ppm)]				
Basis, ppmvd	1.4	1.4	1.4	1.4
Moisture (%)	7.6	8.42	9.07	9.95
Turbine Flow (acfm)	2,737,101	2,656,962	2,593,227	2,507,258
Turbine Exhaust Temperature (°F)	1,096	1,118	1,130	1,147
Emission rate (lb/hr)	2.99	2.84	2.73	2.59
(TPY)	13.1	12.4	12.0	11.3
Lead (lb/hr)= NA				
Emission Rate Basis	NA	NA	NA	NA
Emission rate (lb/hr)	NA	NA	NA	NA
(TPY)	NA	NA	NA	NA

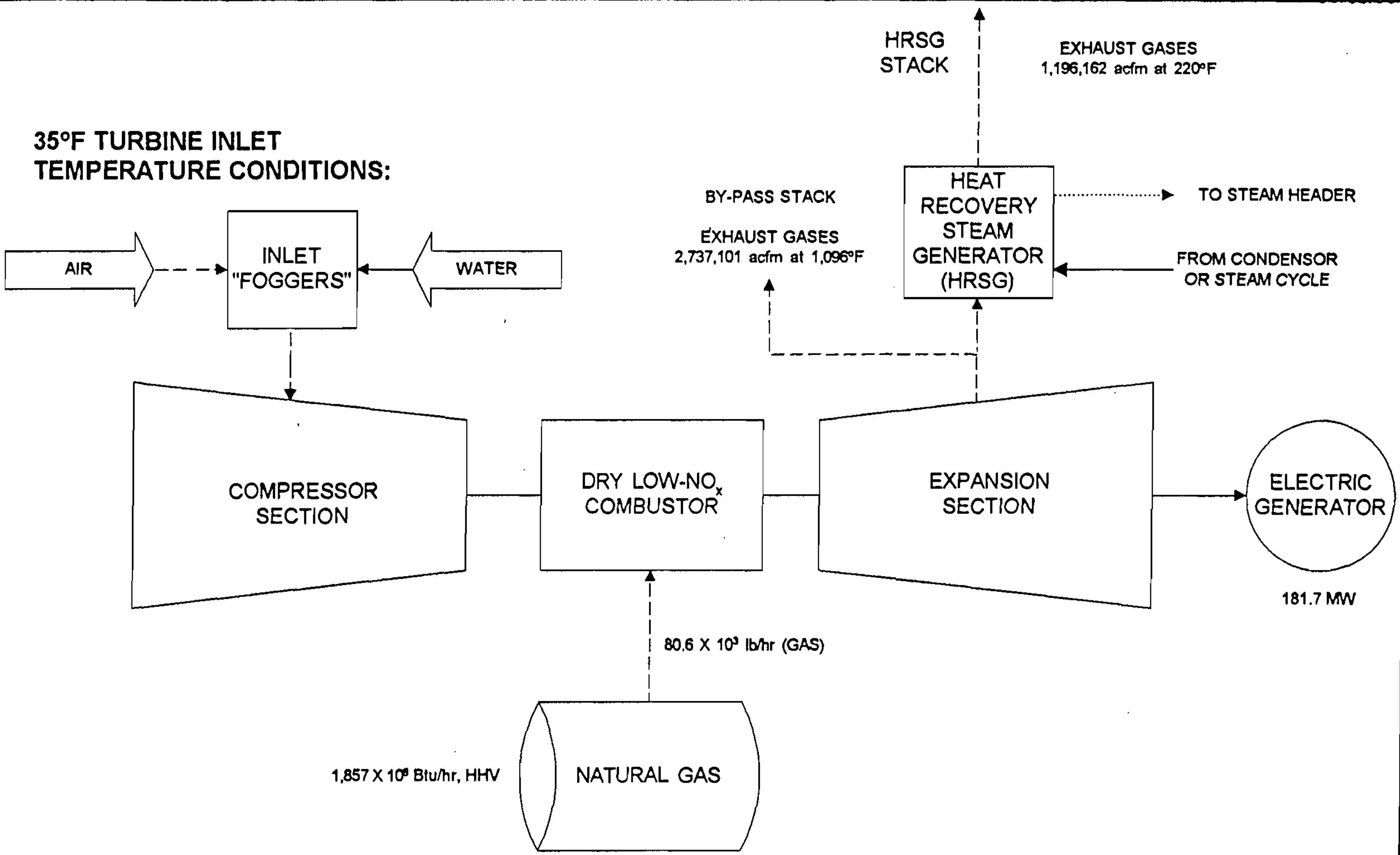
Note: ppmvd= parts per million, volume dry; O_2= oxygen.

Source: GE, 1998; Golder Associates, 1998; EPA, 1996

9837537Y/F1/WP/F2-2.VSD

09/03/98

35°F TURBINE INLET TEMPERATURE CONDITIONS:



NOTE: SEE ATTACHMENT B FOR DESIGN INFORMATION AND STACK PARAMETERS.
BASED ON DATA PROVIDED BY GENERAL ELECTRIC CORPORATION.

FORT MYERS REPOWERING PROJECT	Figure 2-2 Simplified Flow Diagram of GE Frame 7FA Fort Myers Repowering Project	FPL

Attachment PFMU1_2
Fuel Specifications
Natural Gas

Compound	Percent by Volume	Percent by Weight
Methane (CH_4)	95.873	91.45
Ethane (C_2H_6)	2.579	4.61
Propane (C_3H_8)	0.161	0.042
Butane (C_4H_{10})	0.017	0.06
Pentane (C_5H_{12})	0.007	0.03
Hexane (C_6H_{14})	0.027	0.14
Carbon Dioxide (CO_2)	0.883	2.53
Nitrogen (N_2)	0.453	0.76
Total Sulfur (S)	1 gr/100 scf [a]	–
Water Vapor (H_2O)	0.6 lb/MMscf	–

HHV = 23,006 Btu/lb = 1,024 Btu/scf [60°F @ 14.7 pounds per square inch (psi)]

LHV = 20,751 Btu/lb = 924 Btu/scf (60°F @ 14.7 psi)

[a]Typical maximum.

GE Power Generation

Dry Low NOx Combustion Systems for GE Heavy-Duty Gas Turbines

L. Berkley Davis
GE Power Systems
Schenectady, NY

8

LIST OF FIGURES

DRY LOW NO_x COMBUSTION SYSTEMS FOR GE HEAVY-DUTY GAS TURBINES

L.B. Davis
GE Power Systems
Schenectady, NY

ABSTRACT

State-of-the-art emissions control technology for heavy-duty gas turbines is reviewed with emphasis on the operating characteristics and field experience of Dry Low NO_x (DLN) combustors for E- and F- technology machines. The lean premixed DLN systems for gas fuel have demonstrated their ability to meet the ever-lower emission levels required today. Lean premixed technology has also been demonstrated on oil fuel and is also discussed.

INTRODUCTION

The regulatory requirements for low emissions from gas turbine power plants have increased during the past 10 years. Environmental agencies throughout the world are now requiring even lower rates of emissions of NO_x and other pullutants from both new and existing gas turbines. Traditional methods of reducing NO_x emissions from combustion turbines (water and steam injection) are limited in their ability to reach the extremely low levels required in many localities. GE's involvement in the development of both the traditional methods (References 1 through6) and the newer Dry Low NO_x (DLN) technology (References 7 and 8) has been well-documented. This paper focuses on DLN.

Since the commercial introduction of GE's DLN combustion systems for natural-gas-fired heavy-duty gas turbines in 1991, systems have been installed in more than 145 machines, from the most modern F technology (firing temperature class of 2400 F/1316 C) to field retrofits of older machines. As of August 1996, these machines have operated more than one million hours with DLN; more than 290,000 hours have been in the F technology. To meet marketplace demands, GE has developed DLN products broadly classified as either DLN-1, which was developed for E-technology (2000 F/1093 C firing temperature class) machines, or DLN-2, which was developed specifically for the F technology machines and is also being applied to the EC, G and H machines.

Development of these products has required an intensive engineering effort involving both GE Power Systems and GE Corporate Research and Development. This collaboration will continue as DLN is applied to the G and H machines and combustor development for Dry Low NO_x on oil ("dry oil") continues.

This paper presents the current status of DLN-1 technology and experience, including dry oil, and of DLN-2 technology and experience. Background information about gas turbine emissions and emissions control is contained in the Appendix.

DRY LOW NO_X SYSTEMS

Dry Low NO_x Product Plan

Figure 1 shows GE's Dry Low NO_x product offerings for its new and existing machines in three major groupings. The first group includes the MS3000, MS5000 and MS6001B products. The 6B DLN-1 is the technology flagship product for this group and, as can be noted, is available to meet 9 ppm NO_x requirements. Such low NO_x emissions are generally not attainable on lower firing temperature machines such as the MS3000s and MS5000s because carbon monoxide (CO) would be excessive.

The second major group includes the MS7000B/E, MS7001EA and MS9001E machines with the 9 ppm 7EA DLN-1 as the flagship product. The dry oil program focuses initially on this group.

The third group combines all of the DLN-2 products and includes the FA, EC, G and H machines, with the 7FA product as the flagship.

As shown in Figures 2 and 3, most of these products are capable of power augmentation and of peak firing with increased NO_x emissions. With gas fuel, power augmentation with steam is in the premixed mode for both DLN-1 and DLN-2 systems. Power augmentation with water is in the lean-lean mode for DLN-1 and in the premixed mode for DLN-2.

The GE DLN systems integrate a staged pre-

Turbine Model	Gas NOx (ppmvd)	Gas CO (ppmvd)	Gas Diluent	Distillate NOx (ppmvd)	Distillate CO (ppmvd)	Distillate Diluent
MS3002 (J) - RC	33	25	Dry	Not Available		
MS3002 (J) - SC	42	50	Dry			
MS5001P	42	50	Dry	65	20	Water
MS5001R	42	50	Dry	65	20	Water
MS5002C	42	50	Dry	65	20	Water
MS6001 B	25	15	Dry	42	20	Water
	9	25	Dry	42	30	Water/Steam
MS6001 FA	25	15	Dry	42/65	20	Water/Steam
MS7001 B/E Conv	25	25	Dry	42	30	Water
MS7001 EA	25	15	Dry	42	20	Water
	15	25	Dry	42	30	Water/Steam
	9	25	Dry	42	30	Water/Steam
MS7001 EC	25	15	Dry	42/65	20	Water/Steam
MS7001 FA	25	15	Dry	42/65	20	Water/Steam
	9	9	Dry	42/65	30	Water/Steam
MS9001 E	35	15	Dry	42	20	Water
	25	25	Dry	42	20	Water
	25	25	Dry	90	20	Dry
MS7001 H	25	15	Dry	42/65	20	Water/Steam
	9	9	Dry	42/65	30	Water/Steam
MS9001 EC	25	15	Dry	42/65	20	Water/Steam
MS9001 FA	25	15	Dry	42/65	20	Water/Steam
MS9001 H	25	15	Dry	42/65	20	Water/Steam

Notes: 1. NO_x levels are at 15% oxygen. Ambient range 30 F/-1 C to 100 F/38 C

GT24717D

Figure 1. Dry Low NO_x product plan

mixed combustor, the gas turbine's SPEEDTRONIC™ controls and the fuel and associated systems. There are two principal measures of performance. The first is meeting the emission levels required at base load on both gas and oil fuel and controlling the variation of these levels across the load range of the gas turbine.

The second measure is system operability, with emphasis placed on the smoothness and reliability of combustor mode changes, ability to load and unload the machine without restriction, capability to switch from one fuel to another and back again, and system response to rapid transients (e.g., generator breaker open events or rapid swings in load). GE's design goal is to make the DLN system operate so the gas turbine operator does not know whether a DLN or conventional combustion system is installed (i.e., its operation is "transparent to the user"). As August 1996, a significant portion of the DLN design and development effort has focused on system operability.

Design of a successful DLN combustor for a heavy-duty gas turbine also requires the designer to develop hardware features and operational

Turbine Model	NOx @15% O_2 (ppmvd)	Operating Mode	Diluent	Maximum Diluent/Fuel	NO_x at Max D/F (ppmvd)	CO Max D/F (ppmvd)
MS6001(B)	9	Premix	Steam	2.5/1	9	25
		Lean-Lean	Steam	2.5/1	25	15
	25	Premix	Steam	2.5/1	25	15
		Lean-Lean	Water	1.5/1	25	15
		Lean-Lean	Steam	2.5/1	25	15
MS7001(EA)	9	Premix	Steam	2.5/1	9	25
		Lean-Lean	Water	1.5/1	25	15
		Lean-Lean	Steam	2.5/1	25	15
	25	Premix	Steam	2.5/1	25	15
		Lean-Lean	Water	1.5/1	25	15
		Lean-Lean	Steam	2.5/1	25	15
MS7001(FA)	25	Premix	Steam	2.1/1	25	15

GT24556

Figure 2. DLN power augmentation summary — gas fuel

	NO_x-Base (ppmvd)	NO_x-Peak (ppmvd)	CO-Base (ppmvd)	CO-Peak (ppmvd)
MS6001(B)	9 25	18 50	25 15	6 4
MS7001(EA)	9 25	18 50	25 15	6 4
MS7001(FA)	25	35	15	6
MS9001(E)	25	40	15	6

GT24557

Figure 3. DLN peak firing summary — gas fuel

methods that simultaneously allow the equivalence ratio and residence time in the flame zone to be low enough to achieve low NO_x, but with acceptable levels of combustion noise (dynamics), stability at part load operation and sufficient residence time for CO burn-out, hence the designation of DLN combustion design as "four-sided box" (Figure 4).

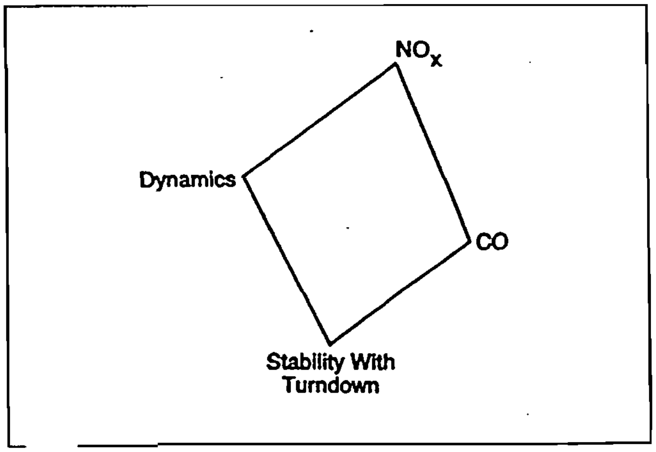
A scientific and engineering development program by GE's Corporate Research and Development Center, Power Systems business and Aircraft Engine business has focused on understanding and controlling dynamics in lean premixed flows. The objectives have been to:

- Gather and analyze machine and laboratory data to create a comprehensive dynamics data base
- Create analytical models of gas turbine combustion systems that can be used to understand dynamics behavior
- Use the analytical models and experimental methods to develop methods to control dynamics

As of August 1996, these efforts have resulted in a large number of hardware and control features that limit dynamics, plus analytical tools that are used to predict system behavior. The latter are particularly useful in correlating laboratory test data from full scale combustors with actual gas turbine data.

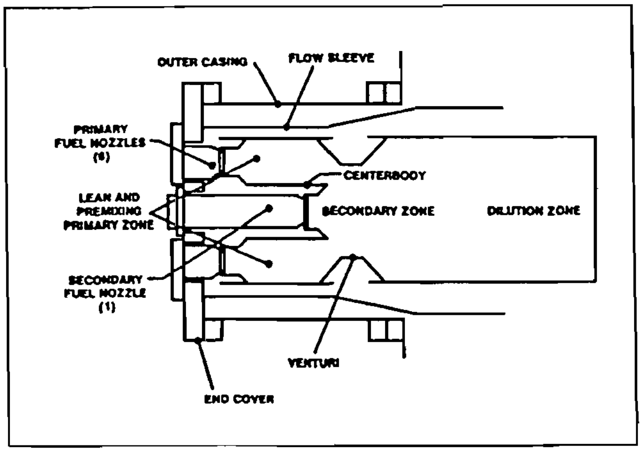
DLN-1 System

DLN-1 development began in the 1970s with the goal of producing a dry oil system to meet the United States Environmental Protection Agency's New Source Performance Standards of 75 ppmvd NO_x at 15% O_2. As noted in Reference 7, this system was tested on both oil and gas fuel at Houston Lighting & Power in



GT23812A

Figure 4. DLN technology — a four-sided box



GT15050A

Figure 5. DLN-1 combustor schematic

1980 and met its emission goals. Subsequent to this, DLN program goals changed in response to stricter environmental regulations and the pace of the program accelerated in the late 1980s.

DLN-1 Combustor

The GE DLN-1 combustor (shown in cross section in Figure 5 and described in Reference 8) is a two-stage premixed combustor designed for use with natural gas fuel and capable of operation on liquid fuel. As shown, the combustion system includes four major components: fuel injection system, liner, venturi and cap/centerbody assembly.

These components form two stages in the combustor. In the premixed mode, the first stage thoroughly mixes the fuel and air and delivers a uniform, lean, unburned fuel-air mixture to the second stage.

The GE DLN-1 combustion system operates in four distinct modes, illustrated in Figure 6, during pre-mixed natural gas or oil fuel operation:

Mode	Operating Range
Primary	Fuel only to the primary nozzles. Flame is in the primary stage only. This mode of operation is used to ignite, accelerate and operate the machine over low- to mid-loads, up to a preselected combustion reference temperature.
Lean-Lean	Fuel to both the primary and secondary nozzles. Flame is in both the primary and secondary stages. This mode of operation is used for intermediate loads between two pre-selected combustion reference temperatures.
Secondary	Fuel to the secondary no; only. Flame is in the secondary zone only. This mode is a transition state between lean-lean and premix modes. This mode is necessary to extinguish the flame in the primary zone, before fuel is reintroduced into what becomes the primary premixing zone.
Premix	Fuel to both primary and secondary nozzles. Flame is in the secondary stage only. This mode of operation is achieved at and near the combustion reference temperature design point. Optimum emissions are generated in premix mode.

The load range associated with these modes varies with the degree of inlet guide vane modulation and, to a smaller extent, with the ambient temperature. At ISO ambient, the premix operating range is 50% to 100% load with IGV modulation down to 42°, and 75% to 100% load with IGV modulation down to 57°. The 42° IGV minimum requires an inlet bleed heat system.

If required, both the primary and second--y fuel nozzles can be dual-fuel nozzles, thus a. .-ing automatic transfer from gas to oil throughout the load range. When burning either natural gas or distillate oil, the system can operate to full load in the lean-lean mode (Figure 6) and in the pre-mixed. Power augmentation with water is the most common reason.

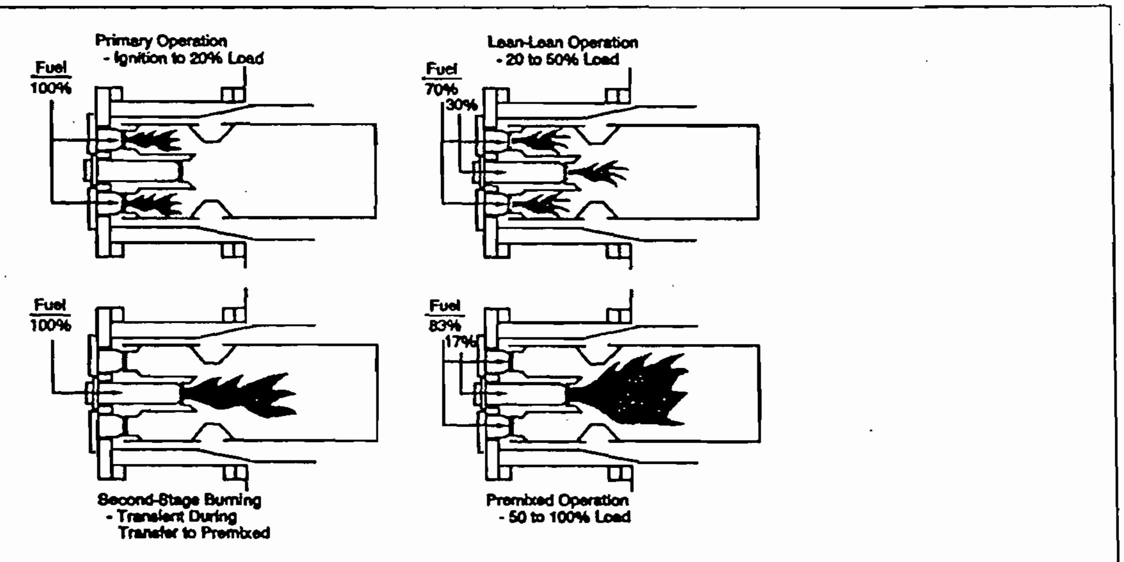


Figure 6. Fuel-staged Dry Low NO_x operating modes

The spark plug and flame detector arrangements in a DLN-1 combustor are different from those used in a conventional combustor. Since first stage must be re-ignited at high load in order to transfer from the premixed mode back to lean-lean operation, the spark plugs do not retract. One plug is mounted in a primary zone cup in each of two combustors. The system uses flame detectors to view the primary stage of selected chambers (similar to conventional systems), and secondary flame detectors that look through the centerbody and into the second stage.

The primary fuel injection system is used during ignition and part load operation. The system also injects most of the fuel during premixed operation and must be capable of stabilizing the flame. For this reason, the DLN-1 primary fuel nozzle is similar to GE's MS7001EA multi-nozzle combustor with multiple swirl-stabilized fuel injectors. The GE DLN-1 system uses five primary fuel nozzles for the MS6001B and smaller machines and six primary fuel nozzles for the larger machines. This design is capable of providing a well-stabilized diffusion flame that burns efficiently at ignition and during part load operation.

In addition, the multi-nozzle fuel injection system provides a satisfactory spatial distribution of fuel flow entering the first-stage mixer. The primary fuel-air mixing section is bound by the combustor first-stage wall, the cap/centerbody and the forward cone of the venturi. This volume serves as a combustion zone when the combustor operates in the primary and lean-lean modes. Since ignition occurs in this stage, crossfire tubes are installed to propagate flame and to balance pressures between adjacent chambers. Film slots on the liner walls provide cooling, as they do in a standard combustor.

In order to achieve good emissions performance in premixed operation, the fuel-air equivalence ratio of the mixture exiting the first-stage mixer must be very lean. Efficient and stable burning in the second stage is achieved by providing continuous ignition sources at both the inner and outer surfaces of this flow. The three elements of this stage comprise a piloting flame, an associated aerodynamic device to force interaction between the pilot flame and the inner surface of the main stage flow, and an aerodynamic device to create a stable flame zone on the outer surface of the main stage flow exiting the first stage.

The piloting flame is generated by the secondary fuel nozzle, which premixes a portion of the natural gas fuel and air (nominally, 17% at full-load operation) and injects the mixture through a swirler into a cup where it is burned. This flame is stabilized by burning an even smaller amount of fuel (less than 2% of the total fuel flow) as a diffusion flame in the cup. The secondary nozzle, which is mounted in the cap centerbody, is simple and highly effective for creating a stable flame.

A swirler mounted on the downstream end of the cap/centerbody surrounds the secondary nozzle. This creates a swirling flow that stirs the interface region between the piloting flame and the main-stage flow and ensures that the flame is continuously propagated from the pilot to the inner surface of the fuel-air mixture exiting the first stage. Operation on oil fuel is similar except that all of the secondary oil is burned in a diffusion flame in the current dry oil design.

The sudden expansion at the throat of the venturi creates a toroidal recirculation zone over the downstream conical surface of the venturi. This zone, which entrains a portion of the venturi cooling air, is a stable burning zone that acts as an ignition source for the main stage fuel-air mixture. The cone angle and axial location of the venturi cooling air dump have significant effects on the efficacy of this ignition source. Finally, the dilution zone (the region of the combustor immediately downstream from the flame zone in the secondary) provides a region for CO burnout and for shaping the gas temperature profile exiting the combustion system.

DLN-1 Controls and Accessories

The gas turbine accessories and control systems are configured so that operation on a DLN-equipped turbine is essentially identical to that of a turbine equipped with a conventional combustor. This is accomplished by controlling the turbines in identical fashions, with the exhaust temperature, speed and compressor discharge pressure establishing the fuel flow and compressor inlet guide vane position.

A turbine with a conventional diffusion combustor that uses diluent injection for NO_X control will use an underlying algorithm to control steam or water injection. This algorithm will use top level control variables (exhaust temperature, speed, etc.) to establish a steam-to-fuel or water-to-fuel ratio to control NO_X.

In a similar fashion, the same variables are used to divide the total turbine fuel flow between the primary and secondary stages of a DLN combustor. The fuel division is accom-

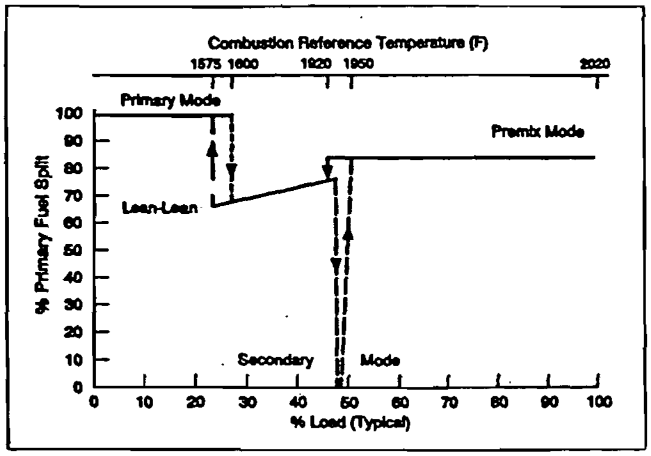


Figure 7. Typical Dry Low NO_x fuel gas split schedule

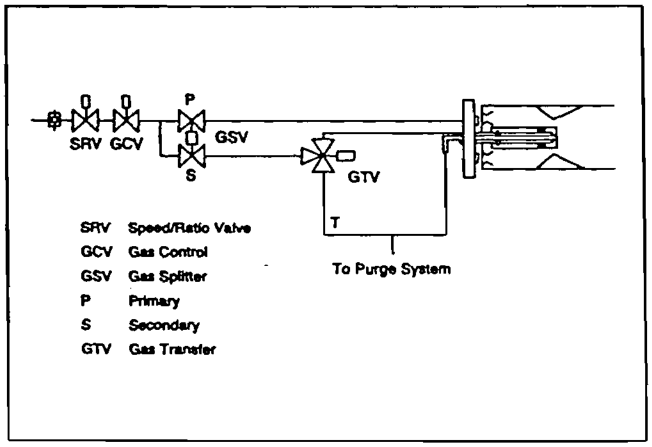


Figure 8. DLN-1 gas fuel system

plished by commanding a calibrated splitter valve to move to a set position based on the calculated combustion reference temperature (Figure 7). Figure 8 shows aschematic of the gas fuel system for a DLN-equipped turbine.

The only special control sequences required are concerned protection of the turbine during a generator breaker-open trip, or flashback, from the second stage to the first stage during premixed operation. When either the breaker opens at load or flashback is sensed by ultraviolet flame detectors looking into the first stage, the splitter valve is commanded to move to a pre-determined position. In the case of a flashback, the control system can execute an automatic sequence to return to premixed, full-load operation.

DLN-1 Emissions

The emissions performance of the GE DLN system can be illustrated as a function of load for a given ambient temperature and turbine configuration. Figures 9 and 10 show the NO_x and CO emissions from typical MS7001EA and MS6001B DLN systems designed for 9 ppm NO_x and 25 ppm CO when operated on natural gas fuel. Note that in premixed operation, NO_x is generally highest at higher loads and CO only approaches 25 ppm at lower premixed loads.

Figures 11 and 12 show NO_x and CO emissions for the same systems operated on oil fuel with water injection for NO_x control, rather than premixed oil. These figures are for units equipped with inlet bleed heat and extended IGV modulation. NO_x and CO emissions from the DLN combustor at loads less than 20% of base load are similar to those from standard combustion systems. This result is expected because both systems are operating as diffusion flame combustors in this range. Between 20% and 50% load, the DLN system is operated in the lean-lean mode, and the flow split between the primary fuel nozzles and secondary nozzle is varied to give the decreasing NO_x characteristic shown.

From 50% to 100% load, the DLN system operates as a lean premixed combustor. As shown in

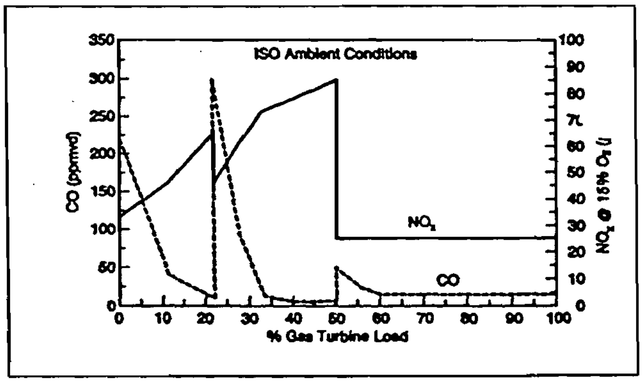


Figure 9. MS7001EA/MS9001E DLN-1 combustion system performance on natural gas fuel

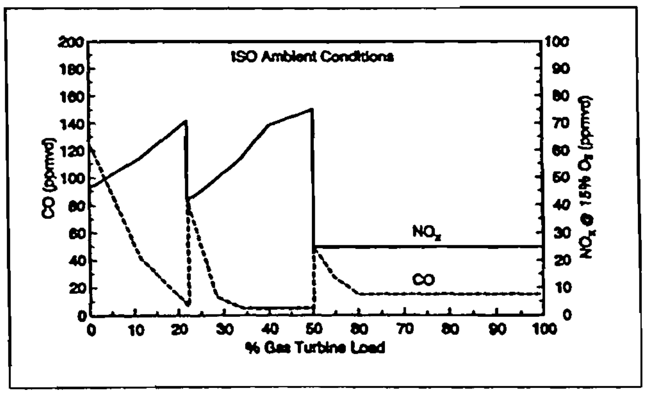
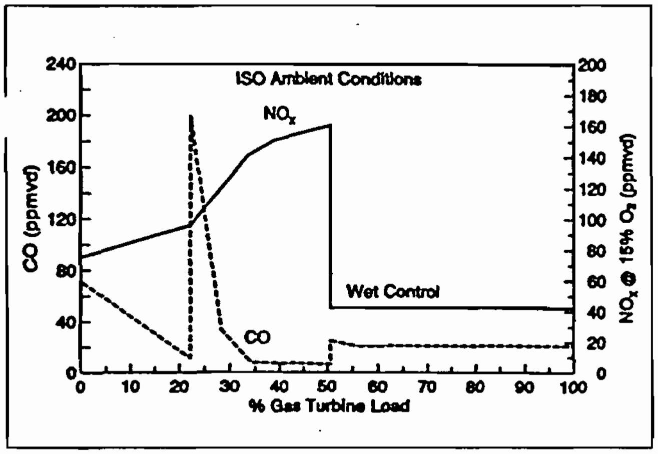
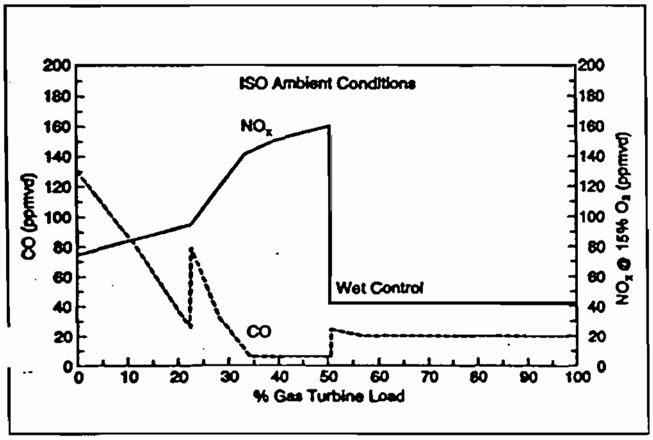


Figure 10. MS6001B DLN-1 emissions performance on natural gas fuel



GT23207B

Figure 11. MS7001EA/MS9001E DLN-1 combustion system performance on distillate oil



GT21766C

Figure 12. MS6001B DLN-1 emissions performance on distillate oil fuel

Figures 9 through 12, NO_x emissions are significantly reduced, while CO emissions are comparable to those from the standard system.

DLN-1 Experience

GE's first DLN-1 system was tested at Houston Lighting & Power in 1980 (Reference 7). A prototype DLN system using the combustor design discussed above was tested on an MS9001E at the Electricity Supply Board's (ESB) Northwall Station in Dublin, Ireland, between October 1989 and July 1990. A comprehensive engineering test of the prototype DLN combustor, controls and associated systems was conducted with NO_x levels of 32 ppmvd (at 15% O_2) obtained at base load. The results were incorporated into the design of prototype systems for the MS7001E and MS6001B.

The 7E DLN-1 prototype was tested at Anchorage Municipal Light and Power (AMLP) in early 1991 and entered commercial service shortly afterward. Since then, development of advanced combustor configurations have been carried out at AMLP. These results have been incorporated into production hardware.

The MS6001B prototype system was first operated at Jersey Central Power & Light's Forked River Station in early 1991. A series of additional tests culminated in the demonstration of a 9 ppm combustor at Jersey Central in November 1993.

As of August 1996, 28 MS6001B machines are equipped with DLN-1 systems. In total, they have accumulated more than 370,000 hours of operation. There are, in addition, four MS7001E, eight MS7001B-E, 26 MS7001EA, 18 MS9001E, one MS5001P and three MS3002J DLN-1 machines that have collectively operated for more than 350,000 hours. Excellent emission results have been obtained in all cases, with single-digit NO_x and CO achieved on several MS7001EAs. Several MS7001E/EA machines have the capability to power augment with either massive water or steam injection.

Starting in early 1992, eight MS7001F machines equipped with GE DLN systems were placed in service at Korea Electric Power Company's Seoinchon site. These F technology machines have achieved better than 55% (gross) efficiency in combined-cycle operation, and the DLN systems are currently operating between 30 and 40 ppmvd NO_x on gas fuel (the guarantee level is 50 ppmvd). These units have operated for more than 150,000 hours. Four additional F technology DLN-1 systems have been commissioned at Scottish Hydro's Keadby site and at National Power's Little Barford site. These 9F machines have operated more than 20,000 hours at less than 60 ppm NO_x.

The combustion laboratory testing and field operation have shown that the DLN-1 system can achieve single digit NO_x and CO levels on E technology machines operating on gas fuel. Current DLN-1 development activity focuses on four goals:

- Application of single-digit technology to the MS6001B, MS7001EA and MS9001E
- Application of DLN-1 technology for retrofitting existing field machines (including MS3002s and MS5000s, some of which will require upgrade before DLN retrofit)
- Completing the development of steam and water power augmentation as needed by the market
- Completing the development of dry oil DLN-1 products.

DLN-2 SYSTEM

As F-technology gas turbines became available in the late 1980s, studies were conducted to establish what type of DLN combustor would be needed for these new higher firing temperature machines. Studies concluded that that air usage in the combustor (e.g., for cooling) other than for mixing with fuel would have to be strictly limited. A team of engineers from GE Power Generation, GE Corporate Research and Development and GE Aircraft Engine proposed a design that repackaged DLN-1 premixing technology but eliminated the venturi and centerbody assemblies that require cooling air.

The resulting combustor is called DLN-2, which is the standard system for the 6FA, 7FA, 9FA, 9EC, 7G, 7H, 9G and 9H machines. Fourteen combustors are installed in the 7FA and 9EC, 18 in the 9FA, and six in the 6FA. These combustors, for all but the 7FA, are not scaled, but are full-size 9FA combustors; the 7FA is slightly smaller.

DLN-2 Combustion System

The DLN-2 combustion system shown in Figure 13 is a single-stage dual-mode combustor that can operate on both gaseous and liquid fuel. On gas, the combustor operates in a diffusion mode at low loads (< 50% load), and a premixed mode at high loads (> 50% load). While the combustor can operate in the diffusion mode across the load range, diluent injection would be required for NO_x abatement. Oil operation on this combustor is in the diffusion mode across the entire load range, with diluent injection used for NO_x control.

Each DLN-2 combustor system has a single burning zone formed by the combustor liner and the face of the cap. In low emissions operation, 90% of the gas fuel is injected through radial gas injection spokes in the premixer, and combustion air is mixed with the fuel in tubes surrounding each of the five fuel nozzles. The premixer tubes are part of the cap assembly. The fuel and air are thoroughly mixed, flow out of the five tubes at high velocity and enter the burning zone where lean, low-NO_x combustion occurs. The vortex breakdown from the swirling flow exiting the premixers, along with the sudden expansion in the liner, are mechanisms for flame stabilization. The DLN-2 fuel nozzle/premixer tube arrangement is similar in design and technology to the secondary nozzle/centerbody of a DLN-1. Five nozzle/premixer tube assem-

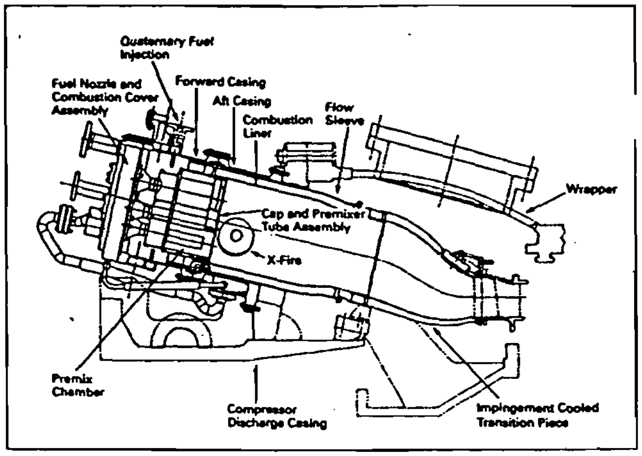


Figure 13. DLN-2 combustion system

blies are located on the head end of the combustor. A quaternary fuel manifold is located on the circumference of the combustion casing to bring the remaining fuel flow to casing injection pegs located radially around the casing.

Figure 14 shows a cross-section of a DLN-2 fuel nozzle. As noted, the nozzle has passages for diffusion gas, premixed gas, oil and water. When mounted on the end cover, as shown in Figure 15, the diffusion passages of four of the fuel nozzles is fed from a common manifold, called the primary, that is built into the end cover. The premixed passage of the same four nozzles are fed from another internal manifold called the secondary. The premixed passages of the remaining nozzle are supplied by the tertiary fuel system; the diffusion passage of that nozzle is always purged with compressor discharge air and passes no fuel.

Figure 15 shows the fuel nozzles installed on the combustion chamber end cover and the

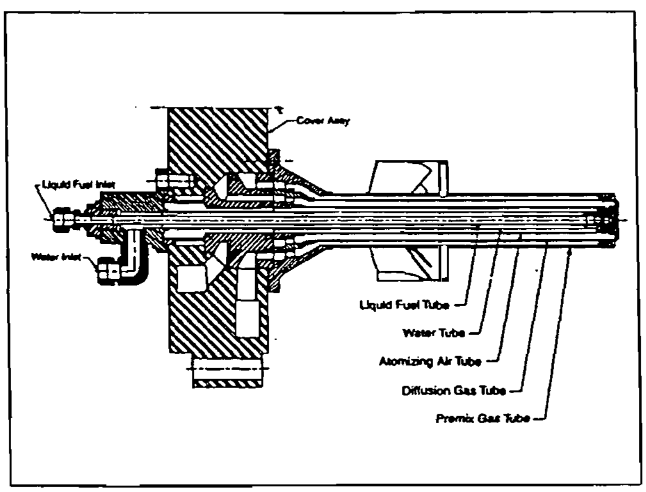


Figure 14. Cross-section of a DLN-2 fuel noz

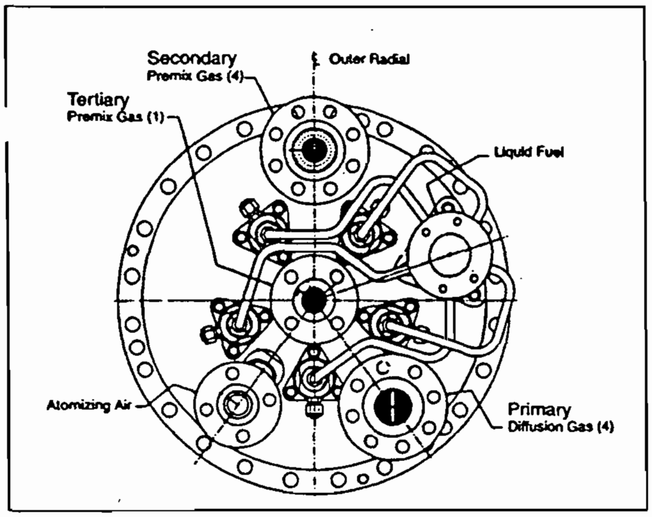


Figure 15. External view of DLN-2 fuel nozzles mounted

connections for the primary, secondary and tertiary fuel systems. DLN-2 fuel streams are:

- Primary fuel — fuel gas entering through the diffusion gas holes in the swirler assembly of each of the outboard four fuel nozzles
- Secondary fuel — premix fuel gas entering through the gas metering holes in the fuel gas injector spokes of each of the outboard four fuel nozzles
- Tertiary fuel — premix fuel gas delivered by the metering holes in the fuel gas injector spokes of the inboard fuel nozzle
- The quaternary system — injects a small amount of fuel into the airstream just upstream from the fuel nozzle swirlers

The DLN-2 combustion system can operate in several different modes.

Primary

Fuel only to the primary side of the four fuel nozzles; diffusion flame. Primary mode is used from ignition to 81% corrected speed.

Lean-Lean

Fuel to the primary (diffusion) fuel nozzles and single tertiary (premixing) fuel nozzle. This mode is used from 81% corrected speed to a preselected combustion reference temperature. The percentage of primary fuel flow is modulated throughout the range of operation as a function of combustion reference temperature. If necessary, lean-lean mode can be operated throughout the entire load range of the turbine. Selecting "lean-lean base on" locks out premix operation and enables the machine to be taken base load in lean-lean.

Premix Transfer

Transition state between lean-lean and premix modes. Throughout this mode, the primary and secondary gas control valves modulate to their final position for the next mode. The premix splitter valve is also modulated to hold a constant tertiary flow split.

Piloted Premix

Fuel is directed to the primary, secondary and tertiary fuel nozzles. This mode exists while operating with temperature control off as an intermediate mode between lean-lean and premix mode. This mode also exists as a default mode out of premix mode and, in the event that premix operating is not desired, piloted premix can be selected and operated to base load. Primary, secondary and tertiary fuel split are constant during this mode of operation.

Premix

Fuel is directed to the secondary, tertiary and quaternary fuel passages and premixed flame exists in the combustor. The minimum load for premixed operation is set by the combustion reference temperature and IGV position. It typically ranges from 50% with inlet bleed heat on to 65% with inlet bleed heat off. Mode transition from premix to piloted premix or piloted premix to premix, can occur whenever the combustion reference temperature is greater than 2200 F/1204 C. Optimum emissions are generated in premix mode.

Tertiary Full Speed No Load (FSNL)

Initiated upon a breaker open event from any load greater than 12.5%. Fuel is directed to the tertiary nozzle only and the unit operates in secondary FSNL mode for a minimum of 20 seconds, then transfers to lean-lean mode.

Figure 16 illustrates the fuel flow scheduling associated with DLN-2 operation. Fuel staging depends on combustion reference temperature and IGV temperature control operation mode.

DLN-2 Controls and Accessories

The DLN-2 control system regulates the fuel distribution to the primary, secondary, tertiary and quaternary fuel system. The fuel flow distribution to each combustion fuel system is a function of combustion reference temperature and IGV temperature control mode. Diffusion, piloted premix and premix flame are established by changing the distribution of fuel flow in the combustor. The gas fuel system (Figure 17) consists of the gas fuel stop/ratio valve, primary gas

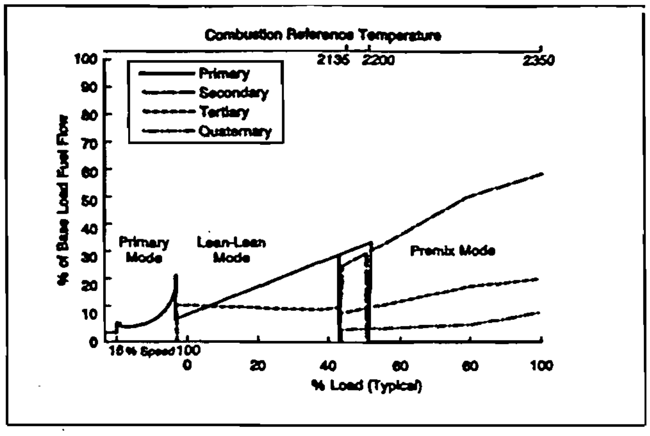


Figure 16. Fuel flow scheduling associated with DLN-2 operation

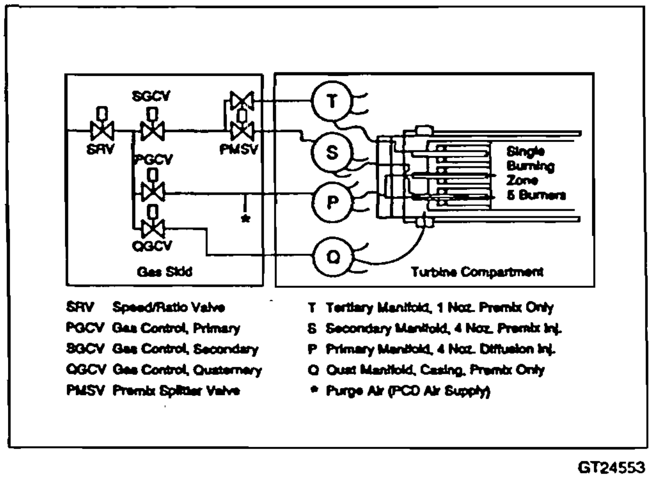


Figure 17. DLN-2 gas fuel system

control valve, secondary gas control valve premix splitter valve and quaternary gas control valve. The stop/ratio valve is designed to maintain a predetermined pressure at the control valve inlet.

The primary, secondary and quaternary gas control valves regulate the desired gas fuel flow delivered to the turbine in response to the fuel command from the SPEEDTRONIC™ controls.

The premix splitter valve controls the fuel flow split between the secondary and tertiary fuel system.

DLN-2 Emissions Performance

Figures 18 and 19 show the emissions performance for a DLN-2 equipped 7FA/9FA for gas fuel and for oil fuel with water injection.

DLN-2 Experience

The first DLN-2 systems were placed in ser-

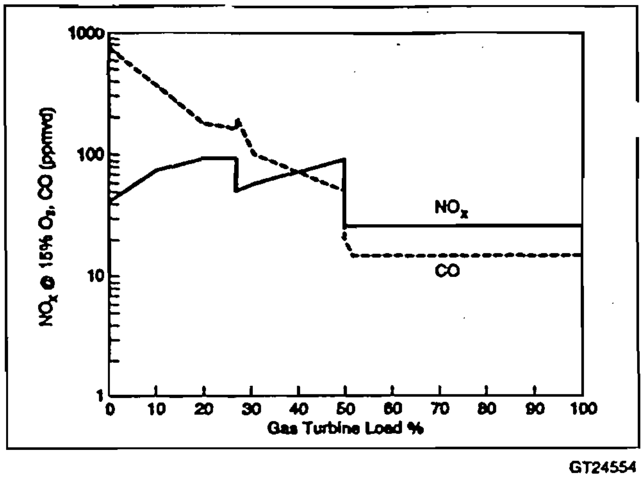


Figure 18. Emissions performance for DLN-2-equipped 7FA/9FA for gas fuel

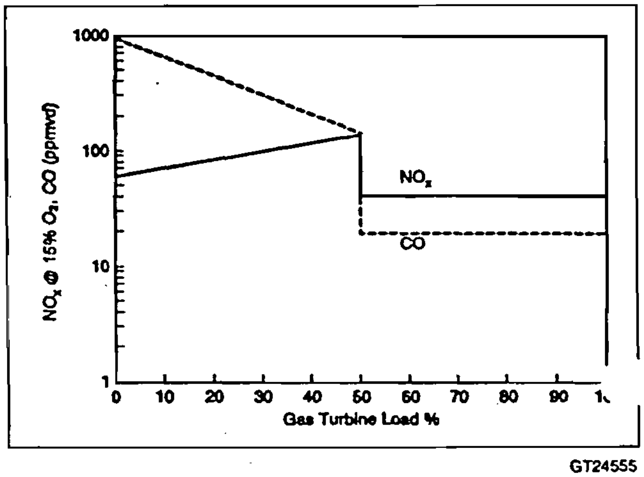


Figure 19. Emissions performance for DLN-2-equipped 7FA/9FA for oil fuel with water injection

vice at Florida Power and Light's Martin Station with commissioning beginning in September 1993, and the first two (of four) 7FA units entering commercial service in February 1994. During commissioning, quaternary fuel was added and other combustor modifications were made to control dynamic pressure oscillations in the combustor.

As of August 1996, 23 DLN-2 7FA and 17 9FA units are in commercial service. They have accumulated more than 150,000 hours of operation. Of these units, 11 are dual-fuel units, and the remainder are gas-only.

CONCLUSION

GE's Dry Low NO_x Program continues to focus on the development of systems capable the extremely low NO_x levels required to me today's regulations and to prepare for more stringent requirements in the future. New unit nroduction needs and the requirements of exist-ẓ machines, are being addressed. GE DLN systems are operating on more than 145 machines and have accumulated more than one million service hours. More than 200 DLN systems have been either put into service, shipped or placed on order. GE is the only manufacturer with F technology machines operating below 25 ppmvd.

APPENDIX

Gas Turbine Combustion Systems

A gas turbine combustor mixes large quantities of fuel and air and burns the resulting mixture. In concept the combustor is comprised of a fuel injector and a wall to contain the flame. There are three fundamental factors and practical concerns that complicate the design of the combustor: equivalence ratio, flame stability, and ability to operate from ignition through full load.

Equivalence ratio

A flame burns best when there is just enough .el to react with the available oxygen. With this stoichiometric mixture (equivalence ratio of 1.0) the flame temperature is the highest and the chemical reactions are the fastest, compared to cases where there is either more oxygen ("fuel lean," < 1.0) or less oxygen ("fuel rich," > 1.0) for the amount of fuel present.

In a gas turbine, the maximum temperature of the hot gases exiting the combustor is limited by the tolerance of the turbine nozzles and buckets. This temperature corresponds to an equivalence ratio of 0.4 to 0.5 (40 to 50% of the stoichiometric fuel flow). In the combustors used on modern gas turbines, this fuel-air mixture would be too lean for stable and efficient burning. Therefore, only a portion of the compressor discharge air is introduced directly into the combustor reaction zone (flame zone) to be mixed with the fuel and burned. The balance of the airflow either quenches the flame prior to the combustor discharge entering the turbine or to cool the wall of the combustor.

Flame stability

Even with only part of the air being introced into the reaction zone, flow velocities in the zone are higher than the turbulent flame speed at which a flame propagates through the fuel-air mixture. Special mechanical or aerodynamic devices must be used to stabilize the flame by providing a low velocity region. Modern combustors employ a combination of swirlers and jets to achieve a good mix and to stabilize the flame.

Operational Stability

The combustor must be able to ignite and to support acceleration and operation of the gas turbine over the entire load range of the machine. For a single-shaft generator-drive machine, speed is constant under load and, therefore, so is the airflow for a fixed ambient temperature. There will be a five- or six-to-one turndown in fuel flow over the load range, and a combustor whose reaction zone equivalence ratio is optimized for full load operation will be very lean at the lower loads. Nevertheless, the flame must be stable and the combustion process must be efficient at all loads.

GE uses multiple-combustion chamber assemblies in its heavy-duty gas turbines to achieve reliable and efficient turbine operation. As shown in Figure A-1, each combustion chamber assembly comprises a cylindrical combustor, a fuel injection system and a transition piece that guides the flow of the hot gas from the combustor to the inlet of the turbine. Figure A-2 illustrates the multiple-combustor concept.

There are several reasons for using the multiple-chamber arrangement instead of large silo-type combustors:

- The configuration permits the entire turbine to be factory assembled, tested and shipped without interim disassembly
- The turbine inlet temperature can be better controlled, thus providing for longer turbine life with reduced turbine cooling air requirements
- Smaller parts can be handled more easily during routine maintenance
- Smaller transition pieces are less susceptible to damage from dynamic forces generated in the combustor; furthermore, the shorter combustion system length ensures that acoustic natural frequencies are higher and less likely to couple with the pressure oscillations in the flame
- Smaller combustors generate less NO_x because of much better mixing and shorter residence time
- As turbine inlet temperatures have increased to improve efficiency, the size of the combustors has decreased to minimize cooling

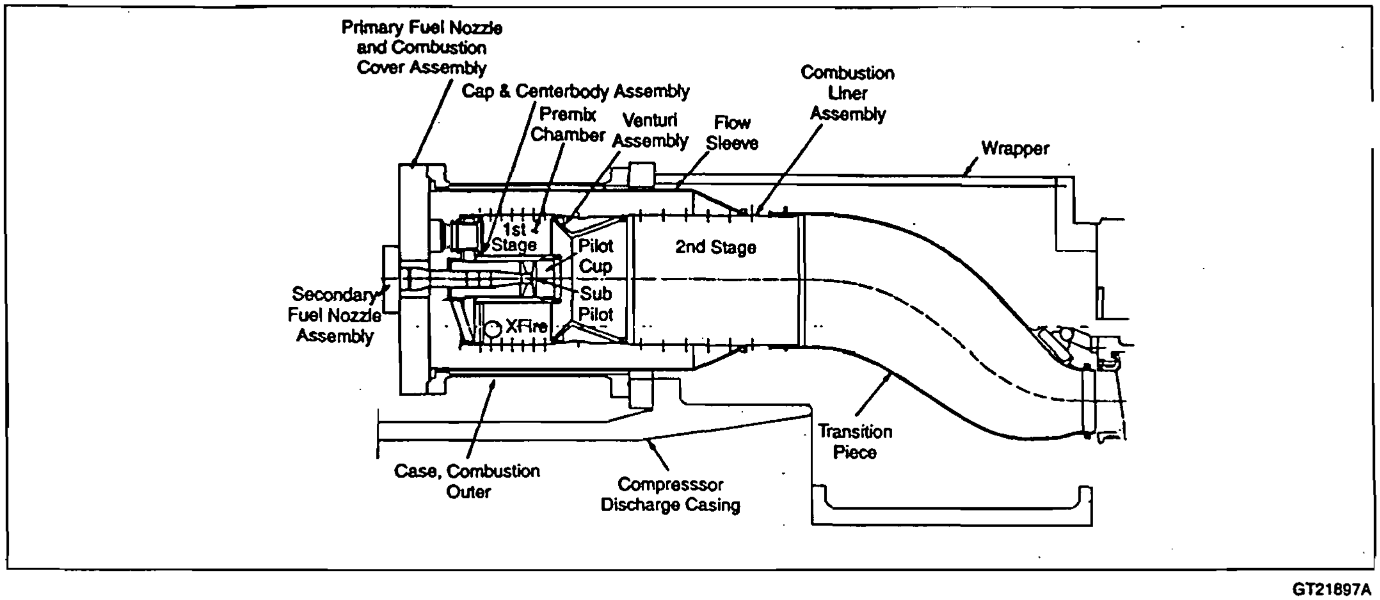


Figure A1. MS7001EA Dry Low NO_x combustion chamber

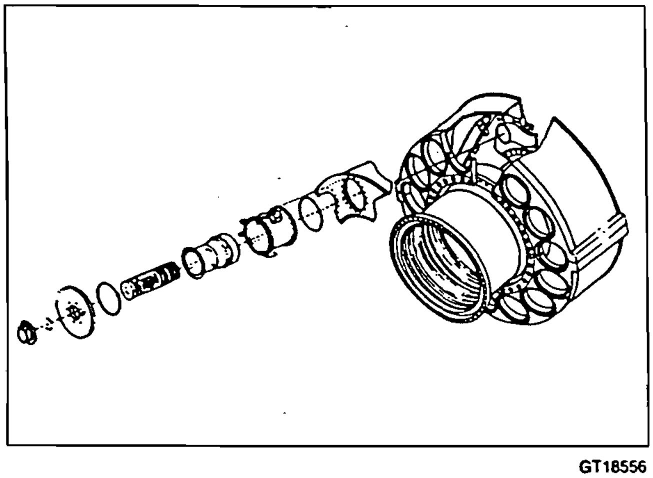


Figure A2. Exploded view of combustion chamber

requirements, as in aircraft gas turbine combustors

- Small can-type combustors can be completely developed in the laboratory through a combination of both atmospheric and full-pressure, full-flow tests. Therefore, there is a higher degree of confidence that a combustor will perform as designed across all load ranges before it is installed and tested in a machine.

Gas Turbine Emissions

The significant products of combustion in gas turbine emissions are:

- Oxides of nitrogen (NO and NO_2, collectively called NO_x)
- Carbon monoxide (CO)
- Unburned hydrocarbons or UHCs (usually expressed as equivalent methane (CH_4) particles and arise from incomplete combustion)
- Oxides of sulfur (SO_2 and SO_3) particulates.

Unburned hydrocarbons include both volatile organic compounds (VOCs), which contribu‑ to the formation of atmospheric ozone, a… compounds, such as methane, that do not.

There are two sources of NO_x emissions in the exhaust of a gas turbine. Most of the NO_x is generated by the fixation of atmospheric nitrogen in the flame, which is called thermal NO_x. Nitrogen oxides are also generated by the conversion of a fraction of any nitrogen chemically bound in the fuel (called fuel-bound nitrogen or FBN). Lower-quality distillates and low-Btu coal gases from gasifiers with hot gas cleanup carry various amounts of fuel-bound nitrogen that must be taken into account when emissions calculations are made. The methods described below to control thermal NO_x emissions are ineffective in controlling the conversion of FBN to NO_x.

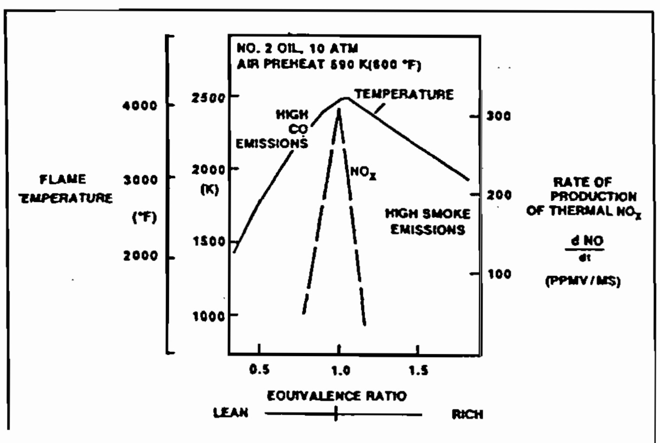
Thermal NO_x is generated by a chemical reaction sequence called the Zeldovich Mechanism (Reference 6). This set of well-verified chemical reactions postulates that the rate of generation of thermal NO_x is an exponential function of the temperature of the flame. The amount of NO_x generated is a function of the flame temperature and of the time the hot ‑ mixture is at flame temperature. This turns ou‑

to be a linear function of time. Thus, temperature and residence time determine thermal NO_x emissions levels and are the principal variles that a gas turbine designer can adjust to control emission levels.

For a given fuel, since the flame temperature is a unique function of the equivalence ratio, the rate of NO_x generation can be cast as a function of the equivalence ratio. Figure A-3, shows that the highest rate of NO_x production occurs at an equivalence ratio of 1.0, when the temperature is equal to the stoichiometric, adiabatic flame temperature.

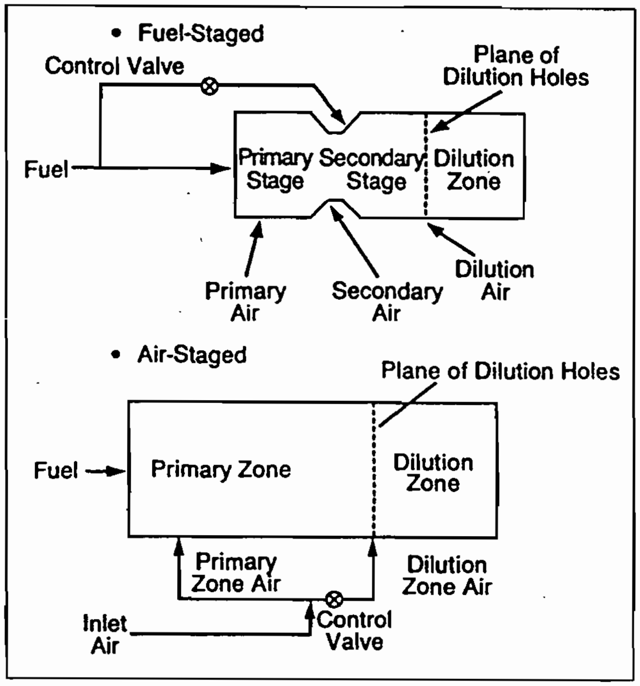
To the left of the maximum temperature point (Figure A-3), more oxygen is available (the equivalence ratio is less than 1.0) and the resulting flame temperature is lower. This is a fuel-lean operation. Since the rate of NO_x formation is a function of temperature and time, it follows that some difference in NO_x emissions can be expected when different fuels are burned in a given combustion system. Since distillate oil and natural gas have approximately a 100 F/38 C flame temperature difference, a significant difference in NO_x emissions can be expected if reaction zone equivalence ratio, water injection rate, etc. are equal.

As shown in Figure A-3, the rate of NO_x production dramatically decreases as flame temperature decreases (i.e., the flame becomes fuel lean). This is because of the exponential effect of temperature in the Zeldovich Mechanism and is the reason why diluent injection (usually water or steam) into a gas turbine combustor flame zone reduces NO_x emissions. For the same reason, very lean dry combustors can be used to control emissions. This is desirable for reaching the lower NO_x levels now required in many applications.



GT11657A

Figure A3. Rate of thermal NO_x production



GT17208-1A

Figure A4. Staged combustors

There are two design challenges associated with very lean combustors. First, care must be taken to ensure that the flame is stable at the design operating point. Secondly, a turndown capability is necessary since a gas turbine must ignite, accelerate, and operate over the load range. At lower loads, as fuel flow to the combustors decreases, the flame will be very lean and will not burn well, or it can become unstable and blow out.

In response to these challenges, combustion system designers use staged combustors so a portion of the flame zone air can mix with the fuel at lower loads or during startup. The two types of staged combustors are fuel-staged and air-staged (Figure A-4). In its simplest and most common configuration, a fuel-staged combustor has two flame zones; each receives a constant fraction of the combustor airflow. Fuel flow is divided between the two zones so that at each machine operating condition, the amount of fuel fed to a stage matches the amount of air available.

An air-staged combustor uses a mechanism for diverting a fraction of the airflow from the flame zone to the dilution zone at low load to increase turndown. These methods can be combined.

Emissions Control Methods

There are three principal methods for controlling gas turbine emissions:

- Injection of a diluent such as water or steam into the burning zone of a conventional (diffusion flame) combustor
- Catalytic clean-up of NO_x and CO from the gas turbine exhaust (usually used in conjunction with the other two methods)
- Design of the combustor to limit the formation of pollutants in the burning zone by utilizing "lean-premixed" combustion technology.

The last method includes both DLN combustors and catalytic combustors. GE has considerable experience with each of these three methods.

Since September 1979, when regulations required that NO_x emissions be limited to 75 ppmvd (parts per million by volume, dry), more than 300 GE heavy-duty gas turbines have accumulated more than 2.5 million operating hours using either steam or water-injection to meet or exceed these required NO_x emissions levels. The amount of water required to accomplish this is approximately one-half of the fuel flow. However, there is a 1.8% heat-rate penalty associated with using water to control NO_x emissions for oil-fired simple-cycle gas turbines. Output, increases by approximately 3%, making water (or steam) injection for power augmentation economically attractive in some circumstances (such as peaking applications).

Single-nozzle combustors that use water or steam injection are limited in their ability to reduce NO_x levels below 42 ppmvd on gas fuel and 65 ppmvd on oil fuel. GE developed multi-nozzle quiet combustors (MNQC) for the MS7001EA and MS7001FA capable of achieving 25 ppmvd on gas fuel and 42 ppmvd on oil, using either water or steam injection. Since October 1987, more than 26 MNQC-equipped MS7001s that use water or steam injection have been placed in service. One unit that uses steam injection has operated nearly 50,000 hours at 25 ppmvd NO_x (at 15% O_2).

Frequent combustion inspections and decreased hardware life are undesirable side effects that can result from the use of diluent injection to reduce NO_x emissions from combustion turbines. For applications that require NO_x emissions below 42 ppmvd (or 25 ppmvd in the case of the MS7001EA or MS7001FA MNQC), or to avoid the significant cycle efficiency penalties incurred when water or steam injection is used for NO_x control, one of the other two principal methods of NO_x control mentioned above must be used.

Selective catalytic reduction (SCR) converts NO and NO_2 in the gas turbine exhaust stream to molecular nitrogen and oxygen by reacting the NO_x with ammonia in the presence of a c alyst. Conventional SCR technology require that the temperature of the exhaust stream remain in a narrow range (550 F to 750 F or 288 C to 399 C) and is restricted to applications with a heat recovery system installed in the exhaust. The SCR is installed at a location in the boiler where the exhaust gas temperature has decreased to the above temperature range. New high-temperature SCR technology is being developed that may allow SCRs to be used for applications without heat recovery boilers.

For an MS7001EA gas turbine, an SCR designed to remove 90% of the NO_x from the gas turbine exhaust stream has a volume of approximately 175 cubic meters and weighs 111 tons. It is comprised of segments stacked in the exhaust duct. Each segment has a honeycomb pattern with passages that are aligned in the direction of the exhaust gas flow. A catalyst, such as vanadium pentoxide, is deposited on the surface of the honeycomb.

SCR systems are sensitive to fuels containing more than 1,000 ppm of sulfur (light distillate oils may have up to 0.8% sulfur). There are two reasons for this sensitivity: first, sulfur poiso the catalyst being used in SCRs.

Secondly, the ammonia will react with sulfur in the presence of the catalyst to form ammonium bisulfate, which is extremely corrosive, particularly near the discharge of a heat recovery boiler. Special catalyst materials that are less sensitive to sulfur have been identified, and there are some theories as to how to inhibit the formation of ammonium bisulfate. This, however, remains an open issue with SCRs.

More than 100 GE units have accumulated more than 100,000 operating hours with SCRs installed. Twenty of the units are in Japan; others are located in California, New Jersey, New York and several other eastern U.S. states. Units operating with SCRs include MS9000s, MS7000s, MS6000s, LM2500s and LM5000s.

Lean premixed combustion is the basis for achieving low emissions from Dry Low NO_x and catalytic combustors. GE has participated in the development of catalytic combustors for many years. These systems use a catalytic reactor bed mounted within the combustor to burn a very lean fuel-air mixture. They have the potential to achieve extremely low emissions levels withc resorting to exhaust gas cleanup. Technical ch lenges in the combustor and in the catalyst and reactor bed materials must be overcome in order to develop an operational catalytic combustor. GE has development programs in place with both ceramic and catalyst manufacturers to address these challenges. GE does not believe commercial systems employing this technology will be available in the near term.

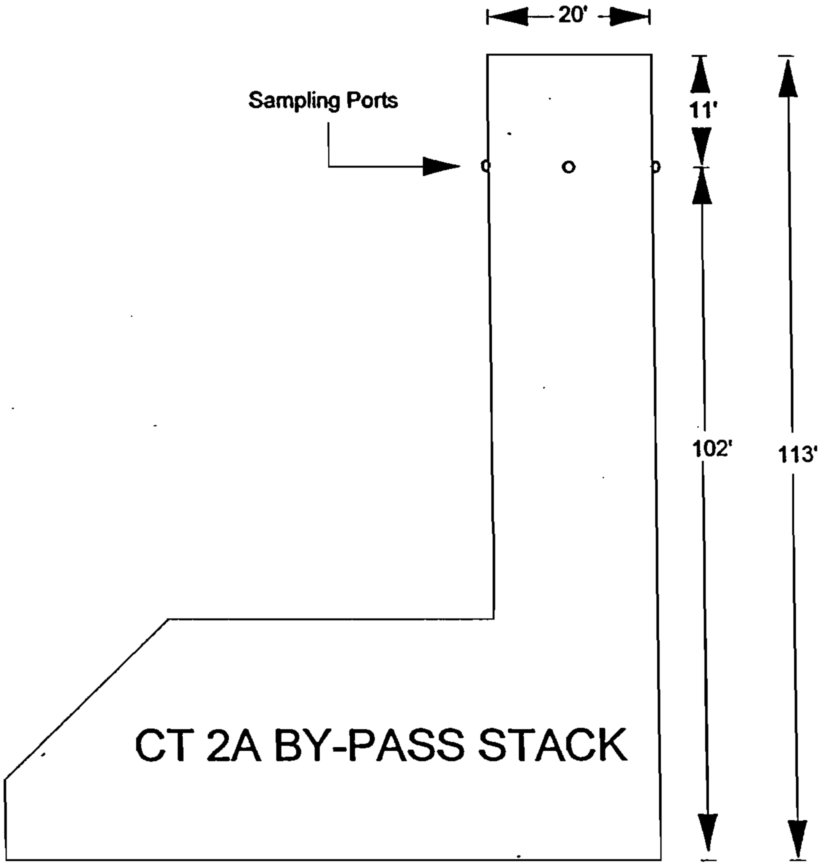
REFERENCES

1. Washam, R. M., "Dry Low NO_x Combustion System for Utility Gas Turbine," ASME Paper 83-JPGC-GT-13, Sept. 1983.
2. Davis, L. B. and Washam, R. M., "Development of a Dry Low NO_x Combustor," ASME Paper No. 89-GT-255, June 1989.
3. Dibelius, N.R., Hilt, M.B., and Johnson, R.H., "Reduction of Nitrogen Oxides from Gas Turbines by Steam Injection," ASME Paper No. 71-GT-58, Dec. 1970.
4. Miller, H. E., "Development of the Quiet Combustor and Other Design Changes to Benefit Air Quality," American Cogeneration Association, San Francisco, March 1988.
5. Cutrone, M. B., Hilt, M. B., Goyal, A., Ekstedt, E. E., and Notardonato, J., "Evaluation of Advanced Combustor for Dry NO_x Suppression with Nitrogen Bearing Fuels in Utility and Industrial Gas Turbines," ASME Paper 81-GT-125, March 1981.
6. Zeldovich, J., "The Oxidation of Nitrogen in Combustion and Explosions," Acta Physicochimica USSR, Vol. 21, No. 4, 1946, pp 577-628.
7. Washam, R. M., "Dry Low NO_x Combustion System for Utility Gas Turbine," ASME Paper 83-JPGC-GT-13, Sept. 1983.
8. Davis, L. B., and Washam, R. M., "Development of a Dry Low NO_x Combustor," ASME Paper No. 89-GT-255, June 1989.

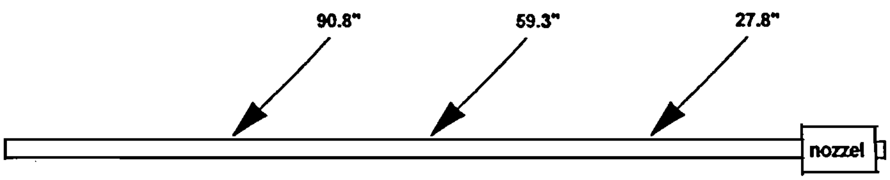
FLORIDA POWER & LIGHT CO.
PFM COMBUSTION TURBINE 2A BY-PASS STACK
SAMPLING SPECIFICATIONS

STACK SPECIFICATIONS

SAMPLING DIAMETER: 240.0 in.
SAMPLING AREA: 314.2 sq. ft.
SAMPLING PORT DEPTH: 12.0 in.
NOTE: DRAWING IS NOT TO SCALE



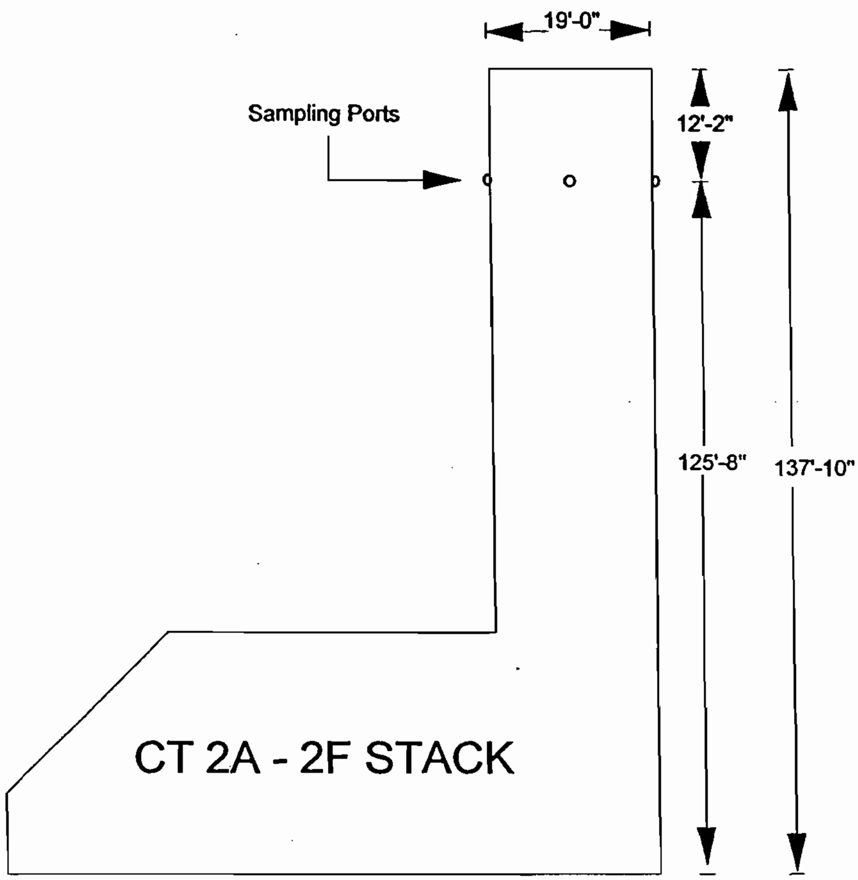
GAS PROBE MARKINGS



Traverse point markings in inches from nozzel.

FILE:PFMCT2A by pass stack

FLORIDA POWER & LIGHT CO.
PFM COMBUSTION TURBINE 2A- 2F STACK SPECIFICATIONS



NOTE: DRAWING IS NOT TO SCALE

FILE:PFMCT2A - 2F stack

Attachment PFMU1_5

Compliance Test Report

The combined cycle Combustion Turbines (2A-2F) are going through their compliance testing in the combined cycle configuration at the time of this application's submittal, therefore, the complete results of the testing will be forwarded to the Department under a separate cover.

7-5-02

Telecon w/ Kevin Washington
Compliance w/ last Revision
OK 8-1-02

Permit Limits

This instruction is to define the emission limits, which will govern the Fort Myers Combustion Turbines. These limits are naturally of vital importance in our Plant operations, and every effort shall be made to operate in compliance. Each operator should be knowledgeable of these limitations.

Each CT must be operated within the emission limits as defined in the plant air-operating permit. The limits for each CT is as follows:

NOX shall not exceed 9ppm as measured with the CEMS and corrected to 15% O2. (30 day rolling average)

CO shall not exceed 12ppm as measured during stack testing.

OPACITY shall not exceed 10%

Excess Emissions

Excess emissions resulting from startup, shutdown or malfunction of the combustion turbines and heat recovery steam generators shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized.

Excess emissions shall in no case exceed 2 hours in any 24 period except during both "cold start up" to and shutdowns from combined cycle operation. During cold start-up to combined cycle operation, up to 4 hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to 3 hours of excess emissions are allowed.

Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours.

Excess emissions from the combustion turbines resulting from start-up of the steam turbine system shall be permitted provided that the best operational practices are adhered to and the duration of excess emissions minimized. Excess emission occurrences shall in no case exceed 12 hours per "cold start-up" of the steam turbine.

Excess Emissions Report

Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably prevented during start-up, shut down or malfunction shall be prohibited.

If excess emissions occur for more than two hours due to a malfunction, the DEPs South District office shall be notified within 1 working day. They shall be advised of the nature, extent and duration of the excess emissions: the cause of the emissions and the action taken to correct the problem.

Best Operational Practices

Best operating practices must always prevail during any period of operation. Best operating practices include any action taken for a given condition which will eliminate/minimize the duration of excess emissions; (i.e.) reducing load, removal from load control, lowering load rate or pressure rate changes.

Emergency situations, equipment failures, and any non-standard occurrence have always called for prompt operator action for a number of reasons. These regulations merely add one more quantitative reason for prompt action. Dropping load, even removing the unit from the line may be necessary to meet the permit limits. As with all operating situations, good judgement regarding equipment and personnel safety, system conditions, and the like is imperative.

Attachment PFMCT2A-2F_11.doc_
Alternative Methods of Operation

CT2A through CT2F can be operated in simple cycle or combined cycle configurations. The Emission limitations apply to both the simple cycle and combined cycle configurations. Normal operation is combined cycle configuration.

PERMITTEE:

Florida Power & Light Company
Fort Myers Power Plant
Post Office Box 430
Fort Myers, Florida 33905

Permit No.	0710002-004AC
Project:	1500 MW Repowering Project
SIC No.	4911
Expires:	December 31, 2002

Authorized Representative:

William Reichel
Plant General Manager

PROJECT AND LOCATION:

Permit to install six (6) combined cycle units to replace two (2) residual oil-fired steam generating units. Each unit is a 170 megawatt General Electric MS7241FA gas-fired combustion turbine-generator with an unfired heat recovery steam generator (HRSG) that will raise sufficient steam to produce another 80 MW via the existing steam-driven electrical generators. The boilers and the tall stacks associated with the existing residual oil-fired units (593 MW total capacity) will be dismantled and replaced by two relatively short stacks per unit for simple and combined operation. The project also includes a cooling tower for once-through brackish water and a small boiler or heaters with a 30-foot stack to heat the natural gas prior to use during simple cycle operation and cold start-ups.

This facility is located at 10650 State Road 80 near Tice, Lee County. UTM coordinates are: Zone 17; 422.3 km E and 2,952.9 km N.

STATEMENT OF BASIS:

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

ATTACHED APPENDICES MADE A PART OF THIS PERMIT:

Appendix GC Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

SECTION I. FACILITY INFORMATION

FACILITY DESCRIPTION

Currently, this facility generates electric power from two residual fuel oil-fired steam units with a combined generating capacity of 593 megawatts (MW) and 12 distillate fuel oil-fired simple cycle combustion turbines with a combined generating capacity of 708 MW.

This permitting action (1500 MW Repowering Project) is to install six (6) combined cycle units to replace two (2) residual oil-fired steam generating units. Each unit is a 170 megawatt General Electric MS7241FA gas-fired combustion turbine-generator with an unfired heat recovery steam generator (HRSG) that will raise sufficient steam to produce another 80 MW via the existing steam-driven electrical generators. The boilers and the tall stacks associated with the existing residual oil-fired units (593 MW total capacity) will be dismantled and replaced by two relatively short stacks per unit for simple and combined operation. The project also includes a cooling tower for once-through brackish water and a small boiler or heaters with a 30-foot stack to heat the natural gas prior to use during simple cycle operation and cold start-ups.

This Project is exempt from the requirements of Rule 62-212.400, F.A.C., Prevention of Significant Deterioration (PSD) as discussed stated in the Technical Evaluation and Preliminary Determination dated September 18, 1998.

EMISSION UNITS

This permit addresses the following emission units:

EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
018 - 023	Power Generation	Six (6) Combined Cycle Combustion Turbine-Generators with Unfired Heat Recovery Steam Generators
024	Fuel Heating	Natural Gas Boiler or Heater(s)
025	Water Cooling	Mechanical Draft Cooling Tower

REGULATORY CLASSIFICATION

This facility, FPL Fort Myers Power Plant, is classified as a Major or Title V Source of air pollution because emissions of at least one regulated air pollutant, such as particulate matter (PM/PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), or volatile organic compounds (VOC) exceeds 100 tons per year (TPY).

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

This facility is a major source of hazardous air pollutants (HAPs) and is also subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

SECTION I. FACILITY INFORMATION

PERMIT SCHEDULE

- 9/30/98 Notice of Intent published in the Fort Myers News-Press
- 09/22/98 Distributed Intent to Issue Permit
- 09/04/98 Received Application
- 05/19/98 Project Presentation

RELEVANT DOCUMENTS:

The documents listed below are the basis of the permit. They are specifically related to this permitting action, but not all are incorporated into this permit. These documents are on file with the Department.

- Application received on September 4, 1998
- Department's Intent to Issue and Public Notice Package dated September 22, 1998.
- EPA comments dated November 03, 1998.
- FPL's comments dated October 28 and November 2, 1998.
- FPL's submittal of revised Phase II Acid Rain application dated November 2, 1998
- FPL's letter dated November 6, 1998 to Director of Environmental Services of Lee County.

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (DEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP South District office, 2295 Victoria Avenue, Suite 364, Ft Myers, Florida 33902-3381 and phone number 941/332-6975.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]
6. Permit Extension: *This permit expires on December 31, 2002.* The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit. [Rule 62-4.080, F.A.C.].
7. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy sent to the Department's South District office. [Chapter 62-213, F.A.C.]
8. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

9. Annual Reports: Pursuant to Rule 62-210.370(2), F.A.C., Annual Operation Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. Annual operating reports shall be sent to the DEP's South District office by March 1st of each year.

10. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C.

11. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1997 version), shall be submitted to the DEP's South District office.

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-103, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 60, 72, 73, and 75.

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

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emission Units 018 through 023, Power Generation, consisting of six (nominal) 170 MW combustion turbines (250 MW in combined cycle operation), shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not required to demonstrate compliance with non-NSPS permit standard(s).

5. ARMS Emission Unit 024, Fuel Heating, shall comply with all applicable provisions of 40CFR60, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, adopted by reference in Rule 62-204.800, F.A.C. This condition shall not apply if FPL actually install direct fired heaters (DFH) instead of a steam boiler.

6. ARMS Emission Unit 025, Cooling Tower, is an unregulated emission unit.

7. All notifications and reports required by the above specific conditions shall be submitted to the DEP's South District office.

GENERAL OPERATION REQUIREMENTS

8. Fuels: Only pipeline natural gas shall be fired in these units. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

9. Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of the fuel to *each* combustion turbine at compressor inlet conditions of 59°F, 60% relative humidity, 100% load, and 14.7 psia shall not exceed 1,760 million Btu per hour (MMBtu/hr).

This maximum heat input rate will vary depending upon turbine inlet conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other compressor inlet conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

10. Steam Boiler (SB) or Direct Fired Heaters (DFHs). The maximum heat input rate, based on the lower heating value (LHV) of the fuel to the SB or DFHs at ambient conditions of 59°F, 60% relative humidity, 100% load, and 14.7 psia shall not exceed 132 MMBtu per hour.

11. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary.

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

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

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

15. Maximum Annual Allowable Hours of operation for each of the six combustion turbines, the cooling tower, and the gas heaters/boiler (ARMS Emission Units 018 - 025) are 8760. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

Control Technology

16. Dry Low NO_X (DLN) combustor shall be installed on each stationary combustion turbine to control nitrogen oxides (NO_X) emissions. [Design, Rule 62-4.070, F.A.C.]

17. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN systems prior to their installation. DLN systems shall each be tuned upon initial

operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. [Rule 62-4.070, and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

18. Following are the emission limits determined for this project assuming full load. Values for NO_X are corrected to 15% O_2. These limits or their equivalents in terms of pounds per hour, as well as the applicable averaging times, are followed by the applicable specific conditions. [Applicant Requests, Rules 62-204.800(7)(b) (Subparts GG and Db), 62-210.200 (Definitions-Potential Emissions), F.A.C.].

Emission Unit	NO_X	CO	VOC	PM/Visibility (% Opacity)	Technology and Comments
Combustion Turbines (each)	9 ppm (30 day) 75/110 ppm (NSPS)	12 ppm	1.4 ppm	10	Dry Low NO_X Combustors Natural Gas, Good Combustion
Gas Heaters/ Boiler	0.10 lb/mmBtu	0.15 lb/mmBtu		10	Low NO_X Burners

19. Nitrogen Oxides (NO_X) Emissions:

- The concentration of NO_X concentrations in the exhaust gas of each CT shall not exceed 9 ppmvd at 15%O_2 on a 30-day rolling average basis as measured by the CEMS (maintained in accordance with 40 CFR 75). Based on CEMS data at the end of each operating day, a new 30-day average rate is calculated from the arithmetic average of all valid hourly emission rates during the previous 30 operating days. In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall exceed neither 9 ppm @15% O_2 nor 65 lb/hr to be demonstrated by initial performance test.
- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate the 30 day rolling average emission rate.
- NO_X emission limit from the gas heaters/boiler shall not exceed 0.10 lb/mmBtu (at ISO conditions) to be demonstrated by stack test.

20. Visible Emissions (VE): VE emissions shall not exceed 10 percent opacity. Visible emissions from the gas heaters/steam boiler shall not exceed 10 percent opacity.

21. Carbon Monoxide (CO) emissions: The concentration of CO (@15% O_2 in the exhaust gas shall not exceed 12 ppmvd as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 43 lb/hr (per CT) to be demonstrated by stack test.

22. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the exhaust gas shall not exceed 1.4 ppmvd as determined by EPA Methods 18 or 25 A. VOC emissions (at ISO conditions) shall not exceed 2.9 lb/hr per CT to be demonstrated by initial stack test.

23. Sulfur Dioxide (SO_2) emissions: As per Condition 8.

EXCESS EMISSIONS

24. Excess Emissions Requirements:

- Excess emissions resulting from startup, shutdown, or malfunction of the *combustion turbines and heat recovery steam generators* shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during both "cold start-up" to or shutdowns from combined cycle operation. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours.
- Excess emissions from the combustion turbines resulting from startup of the *steam turbines system* shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed 12 hours per cold startup of the steam turbine system.

[Applicant Request (FPL estimates that, on average, there will be approximately 12 startups to combined-cycle operation per year), G.E. Combined Cycle Startup Curves Data and Rules 62-210.700, 62-4.130 F.A.C.].

1. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C.

2. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's South District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, periods of startup, shutdown, malfunction, and fuel switching shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 18 and 19. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1997 version)].

COMPLIANCE DETERMINATION

3. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate at which each unit will be operated, but not later than 180 days following initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C.

4. Initial (I) performance tests shall be performed pursuant to 40 CFR Subpart GG. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on each CT as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

   - EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
   - EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
   - EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG.
   - EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
   - EPA Reference Method 19. "Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide, and Nitrogen Oxides Emission Rates". Method 19 shall be used only for the calculation of lb/mmBtu and 40CFR75 shall be used to calculate mmBtu/hr and lb/hr emissions rates from stack tests. Initial test only.

5. Continuous compliance with the NO_X emission limits: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on a 30-day rolling average. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new 30 day average emission rate is calculated from the arithmetic average of all valid hourly emission rates during the previous 30 operating days. Valid hourly emission rates shall not include periods of startup, shutdown, or malfunction. A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40CFR75]

6. Compliance with the SO_2 and PM/PM_{10} emission limits: Notwithstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas is the method for determining compliance for SO_2 and PM_{10}.

For the purposes of demonstrating compliance with the 40 CFR 60.333, natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. Gas analysis, if conducted, 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 pursuant to 40 CFR 60.335(e) (1997 version). However, the applicant is responsible for ensuring that the procedures in 40CFR 60.335 or 40CFR75 are used for determination of fuel sulfur content if gas analysis is done.

7. Compliance with CO emission limit: An initial test for CO, shall be conducted concurrently with the initial NO_X test while operating at permitted capacity. These initial NO_X and CO test results shall be the average of three runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual NOx RATA testing which is performed pursuant to 40 CFR 75.

8. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, CO emission limit will be employed as a surrogate and no annual testing is required.

9. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average compressor inlet temperature during the test (with 100 percent represented by a curve depicting heat input vs. compressor inlet temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. compressor inlet temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for compressor inlet temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Test procedures shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapter 62-204 and 62-297 F.A.C.

10. Test Notification: The DEP's South District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).

11. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

12. Test Results: Compliance test results shall be submitted to the DEP's South District office no later than 45 days after completion of the last test run.

NOTIFICATION, REPORTING, AND RECORDKEEPING

13. Records: All measurements, records, and other data required to be maintained by the permittee shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.

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

MONITORING REQUIREMENTS

15. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from each CT. Thirty day rolling average periods when NO_X emissions (ppmvd @ 15% oxygen) are above the standards, listed in Specific Condition No 18 and 19, shall be provided to the DEP South District Office within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternately by facsimile within one working day). [Rule 62-210.700 and 62-4.130, F.A.C].

16. CEMS for reporting excess emissions:, The NO_X CEMS may be used in lieu of the requirement for reporting excess emissions in 40 CFR 60.334(c)(1), Subpart GG (1997 version). Upon request from DEP, the CEMS emission rates for NO_X on each CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.

17. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62 .

18. Natural Gas Monitoring Schedule: The following custom monitoring schedule for natural gas is approved in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2):

    - The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.

- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative (DR), that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

1. Determination of Process Variables:
   - The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
   - Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh 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]
2. Subpart Db Monitoring: The Permittee shall comply with the applicable monitoring requirements of 40CFR60, Subpart Db for the steam boiler.

Phase II Acid Rain Part Application

For more information, see instructions and refer to 40 CFR 72.30 and 72.31 and Chapter 62-214, F.A.C.

This submission is: ☐ New ☒ Revised

STEP 1
Identify the source by plant name, State, and ORIS code from NADB

Plant Name **Fort Myers Plant** State FL ORIS Code **000612**

STEP 2 Enter the unit ID# for each affected unit and indicate whether a unit is being repowered and the repowering plan being renewed by entering "yes" or "no" at column c. For new units, enter the requested information in columns d and e.

a	b	c	d	e
	Compliance Plan			
Unit ID#	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units Commence Operation Date	New Units Monitor Certification Deadline
FM2CTA	Yes	N/A	1/1/2001	4/1/2001
FM2CTB	Yes	N/A	2/1/2001	5/11/2001
FM2CTC	Yes	N/A	3/1/2001	6/1/2001
FM2CTD	Yes	N/A	4/1/2001	7/1/2001
FM2CTE	Yes	N/A	5/1/2001	8/1/2001
FM2CTF	Yes	N/A	6/1/2001	9/1/2001
PFM3A	Yes	N/A	6/1/2003	9/1/2003
PFM3B	Yes	N/A	6/1/2003	9/1/2003
	Yes			
	Yes			
	Yes			
	Yes			

STEP 3
Check the box if the response in column c of Step 2 is "Yes" for any unit

☐ For each unit that is being repowered, the Repowering Extension Plan form is included.

Plant Name (from Step 1) **Fort Myers Plant**

STEP 4
Read the standard requirements and certification, enter the name of the designated representative, and sign and date

Standard Requirements

Acid Rain Part Requirements.

(1) The designated representative of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Submit a complete Acid Rain part application (including a compliance plan) under 40 CFR part 72 and Rules 62-214.320 and 330, F.A.C., in accordance with the deadlines specified in Rule 62-214.320, F.A.C.; and
(ii) Submit in a timely manner any supplemental information that the Department determines is necessary in order to review an Acid Rain part application and issue or deny an Acid Rain part;
(2) The owners and operators of each Acid Rain source and each Acid Rain unit at the source shall:
(i) Operate the unit in compliance with a complete Acid Rain part application or a superseding Acid Rain part issued by the Department; and
(ii) Have an Acid Rain Part.

Monitoring Requirements.

(1) The owners and operators and, to the extent applicable, designated representative of each Acid Rain source and each Acid Rain unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75, and Rule 62-214.420, F.A.C.
(2) The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.
(3) The requirements of 40 CFR part 75 shall not affect the responsibility of the owners and operators to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements of the Act and other provisions of the operating permit for the source.

Sulfur Dioxide Requirements.

(1) The owners and operators of each source and each Acid Rain unit at the source shall:
(i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and
(ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide.
(2) Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act.
(3) An Acid Rain unit shall be subject to the requirements under paragraph (1) of the sulfur dioxide requirements as follows:
(i) Starting January 1, 2000, an Acid Rain unit under 40 CFR 72.6(a)(2); or
(ii) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR part 75, an Acid Rain unit under 40 CFR 72.6(a)(3).
(4) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.
(5) An allowance shall not be deducted in order to comply with the requirements under paragraph (1)(i) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.
(6) An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain part application, the Acid Rain part, or an exemption under 40 CFR 72.7, 72.8, or 72.14 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.
(7) An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right.

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

(1) Unless otherwise provided, the owners and operators of the source and each Acid Rain unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time prior to the end of 5 years, in writing by the EPA or the Department:
(i) The certificate of representation for the designated representative for the source and each Acid Rain unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with Rule 62-214.350, F.A.C.; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;
(ii) All emissions monitoring information, in accordance with 40 CFR part 75, provided that to the extent that 40 CFR part 75 provides for a 3-year period for recordkeeping, the 3-year period shall apply;
(iii) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

Plant Name (from Step 1) FORT MYERS PLANT

Recordkeeping and Reporting Requirements (cont)

(iv) Copies of all documents used to complete an Acid Rain part application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

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

Liability.

(1) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete Acid Rain part application, an Acid Rain part, or an exemption under 40 CFR 72.7, 72.8 or 72.14, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to section 113(c) of the Act.
(2) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to section 113(c) of the Act and 18 U.S.C. 1001.
(3) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.
(4) Each Acid Rain source and each Acid Rain unit shall meet the requirements of the Acid Rain Program.
(5) Any provision of the Acid Rain Program that applies to an Acid Rain source (including a provision applicable to the designated representative of an Acid Rain source) shall also apply to the owners and operators of such source and of the Acid Rain units at the source.
(6) Any provision of the Acid Rain Program that applies to an Acid Rain unit (including a provision applicable to the designated representative of an Acid Rain unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR part 75 (including 40 CFR 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one Acid Rain unit shall not be liable for any violation by any other Acid Rain unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.
(7) Each violation of a provision of 40 CFR parts 72, 73, 75, 76, 77, and 78 by an Acid Rain source or Acid Rain unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act.

Effect on Other Authorities. No provision of the Acid Rain Program, an Acid Rain part application, an Acid Rain part, or an exemption under 40 CFR 72.7, 72.8, or 72.14 shall be construed as:

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an Acid Rain source or Acid Rain unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;
(2) Limiting the number of allowances a unit can hold; *provided,* that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act;
(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;
(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,
(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

Certification

I 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.

Name	David W. Knutson		
Signature	David W. Knutson	Date	11/21/01

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

[X] 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. Regulated or Unregulated Emissions Unit? (Check one)

[X] 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.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Natural Gas Heater(s) 2A through 2F

4. Emissions Unit Identification Number: [ ] No ID [ ] ID Unknown

024

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**10/03/2000**	**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

The emission unit is a direct-fired heater that uses natural gas to heat the bulk of the natural gas fuel prior to combustion during simple cycle operation only. Each combustion turbine has an individual heater (2A-2F).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Low NO_x Burners**
2. Control Device or Method Code(s): **25**

Emissions Unit Details

1. Package Unit: Manufacturer: **Gastech Engineering Corp.**	Model Number: **FGA-HX-2**
2. Generator Nameplate Rating:	MW
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		**17.1**	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	**8,760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum Heat Input Rate = 17.1 Maximum heat input based on manufacturer's design data.**			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

62-210.300, F.A.C.	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See Figure 2-3**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **21** feet	7. Exit Diameter: **2** feet
8. Exit Temperature: **375** °F	9. Actual Volumetric Flow Rate: **4,639** 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): **422.3** North (km): **2953.03**	
14. Emission Point Comment (limit to 200 characters):	

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment __1___ of __1___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **External Combustion Boilers – Electric Generation – Natural Gas – Boilers > 100 Million Btu/hr except Tangential**		
2. Source Classification Code (SCC): **1-01-006-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **0.017**	5. Maximum Annual Rate: **146**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,024**
10. Segment Comment (limit to 200 characters):		

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NO_x	**025**		**EL**
CO			**EL**

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_x**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **1.71** lb/hour **7.5** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.1 lb/MMBtu** Reference: **File No. 0710002-004-AC**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): $\frac{\textbf{17.1mmBTU/hr X 0.1 lb./mmBTU X 8,760 hr/year}}{\textbf{2,000 lb/ton}}$ = **7.5 tons/year**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Potential tons/year based on 8,760 hours / year operation.**	

Allowable Emissions Allowable Emissions __1__ of __1__

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.1 lb/MMBtu**	4. Equivalent Allowable Emissions: **1.71** lb/hour **7.5** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 7E**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Initial stack test for two of six units required by FDEP File No. 0710002-004-AC.**	

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:	
3. Potential Emissions: **2.57** lb/hour **11.2** tons/year		4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: **0.15 lb/MMBtu** Reference: **File No. 0710002-004-AC**		7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): $\frac{\textbf{17.1 mmBTU/hr.X 0.15 lb/mmBTU X 8,760 hr/year}}{\textbf{2,000 lb/ton}} = \textbf{11.2 tons/year}$		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Potential tons/year based on 8,760 hours / year operation**		

Allowable Emissions Allowable Emissions __1__ of __1__

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.15 lb/MMBtu**	4. Equivalent Allowable Emissions: **2.57** lb/hour **11.2** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; Initial Compliance Test only; two of six units**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **See FDEP File no. 0710002-004-AC.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE10**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters): **FDEP File no. 0710002-004-AC; No annual testing requirement established.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units 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:	
5. Installation Date	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested 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 (limit to 200 characters): **FDEP Rule 62-210.700(1). Allowed for 2 hours (120 minutes) per 24 hours.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units 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:	
5. Installation Date	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1.	Process Flow Diagram [X] Attached, Document ID: **Figure 2-2** [ ] Not Applicable [ ] Waiver Requested
2.	Fuel Analysis or Specification [X] Attached, Document ID: **PFMU1_2** [ ] Not Applicable [ ] Waiver Requested
3.	Detailed Description of Control Equipment [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
4.	Description of Stack Sampling Facilities [X] Attached, Document ID: **PFMCTHeater2A ; PFMCTHeater2B** [ ] Not Applicable [ ] Waiver Requested
5.	Compliance Test Report [ ] Attached, Document ID:________ [X] Previously submitted, Date: **2A - 11/08/2000 2B - 11/28/2000** [ ] Not Applicable
6.	Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7.	Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8.	Supplemental Information for Construction Permit Application [ ] Attached, Document ID:________ [X] Not Applicable
9.	Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [X] Not Applicable
10.	Supplemental Requirements Comment:

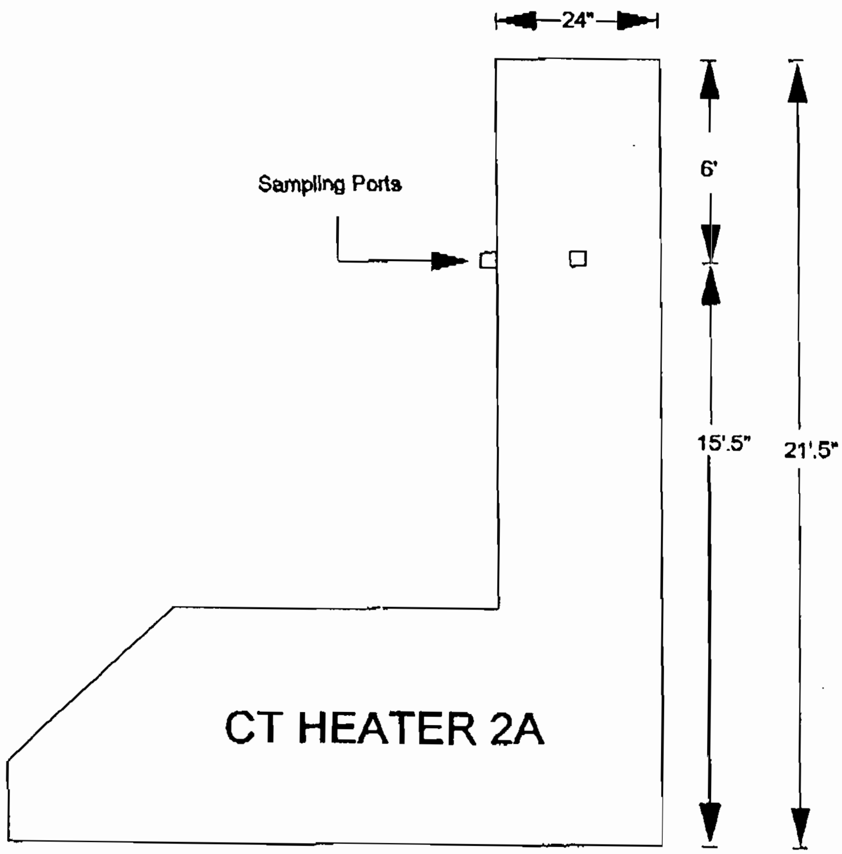
Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:__________ [X] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [X] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [X] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [X] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [X] Not Applicable

FLORIDA POWER & LIGHT CO.
PFM CT HEATER No. 2A

STACK SPECIFICATIONS

SAMPLING DIAMETER: 24 in.
SAMPLING AREA: 3.14 sq. ft.
SAMPLING PORT DEPTH: 6.0 in.
NOTE: DRAWING IS NOT TO SCALE

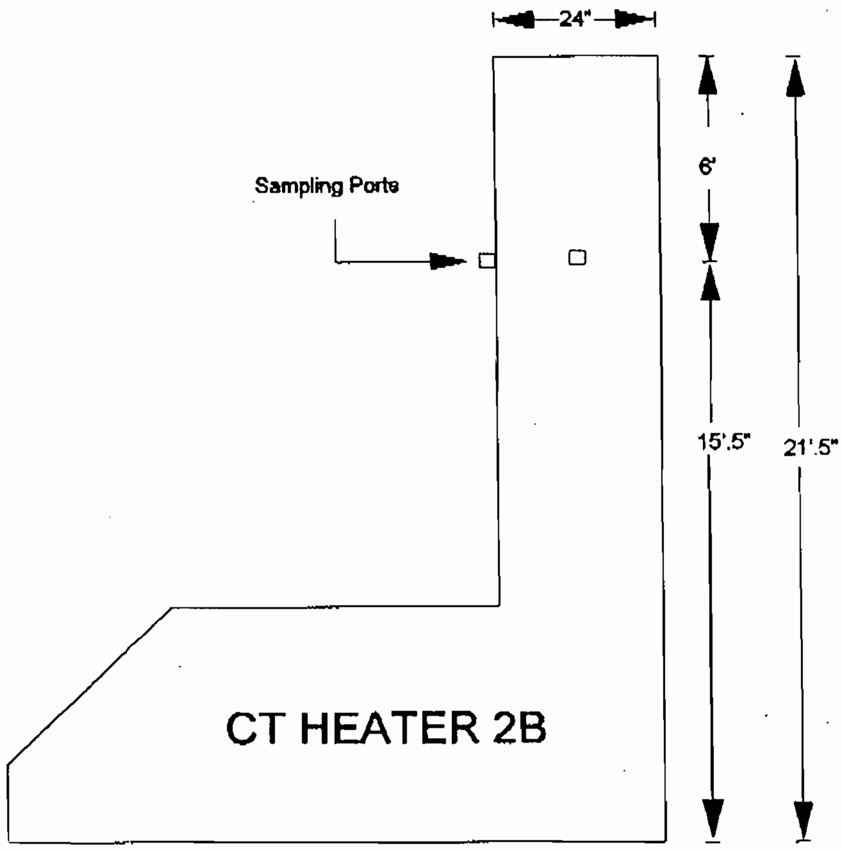


FILE:PFMCTHeater2A

FLORIDA POWER & LIGHT CO.
PFM CT HEATER No. 2B

STACK SPECIFICATIONS

SAMPLING DIAMETER: 24 in.
SAMPLING AREA: 3.14 sq. ft.
SAMPLING PORT DEPTH: 6.0 in.
NOTE: DRAWING IS NOT TO SCALE



FILE:PFMCTHeater2B

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

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).

[X] 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. Regulated or Unregulated Emissions Unit? (Check one)

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

[X] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Mechanical Draft Cooling Tower

4. Emissions Unit Identification Number: **025**

[ ] No ID
[ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	**06/30/2001**	**49**	[ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

A mechanical draft cooling tower which uses brackish water with a total dissolved solids content up to 30,000 ppm. A small portion of the water will be emitted as drift, which will form particulate matter.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Mist Eliminator**
2. Control Device or Method Code(s): **15**

Emissions Unit Details

1. Package Unit: **Mechanical draft cooling tower** Manufacturer: **Balcke-Durr**	Model Number: **CT-1043**
2. Generator Nameplate Rating:	MW
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment __1__ of __1__

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Circulating Water Rate**		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate: **10.2**	5. Maximum Annual Rate: **36,720**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): **Maximum Hourly Rate and Annual Rate in millions of gallons. Annual rate based on five months of operation**		

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	**014**		**NS**
PM10	**014**		**NS**

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________ [X] Not Applicable
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID:________ [X] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
[ ] Attached, Document ID:________ [X] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
[ ] Attached, Document ID:________ [X] Not Applicable

13. Identification of Additional Applicable Requirements
[ ] Attached, Document ID:________ [X] Not Applicable

14. Compliance Assurance Monitoring Plan
[ ] Attached, Document ID:________ [X] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

[ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
Attached, Document ID:________

[ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
Attached, Document ID:________

[ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
Attached, Document ID:________

[ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
Attached, Document ID:________

[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
Attached, Document ID:________

[ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
Attached, Document ID:________

[X] Not Applicable

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

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).

[X] 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. Regulated or Unregulated Emissions Unit? (Check one)

[X] 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.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):

Combustion Turbines #1 - #12 (GT Units 1-12)

4. Emissions Unit Identification Number: **003-014** [ ] No ID [ ] ID Unknown

9. Emissions Unit Status Code: **A**	9. Initial Startup Date: **APRIL 1974**	9. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

Units 003 through 014 are fuel oil fired combustion turbines manufactured by the General Electric Company, each with a rated gross capacity of 63 megawatts (MW). Foggers were installed at the compressor inlet to each of the twelve combustion turbines during 1999. The twelve foggers may operate up to 6,000 hours per year in aggregate (average 500 hours per unit per year).

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):
2. Control Device or Method Code(s):

Emissions Unit Details

1. Package Unit: **Combustion Turbine** Manufacturer: **General Electric**	Model Number: **MS7000B**
2. Generator Nameplate Rating:	**59** MW **Each**
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:			**895**	mmBtu/hr
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:				
4. Maximum Production Rate:				
5. Requested Maximum Operating Schedule:				
		hours/day		days/week
		weeks/year	**8760**	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **The heat input rate given above is for each turbine while firing distillate fuel oil at 25 degree F turbine inlet or, 760 mmBtu heat input per hour at 59 degrees F turbine inlet.**				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

Rule 62-4.070, F.A.C.	Rule 62-4.160(2), F.A.C.
Rule 62-204.800, F.A.C.	Rule 62-210.200, F.A.C.
Rule 62-210.300, F.A.C.	Rule 62-210.700(1), F.A.C.
Rule 62-210.700(4), F.A.C.	Rule 62-210.700(6), F.A.C.
Rule 62-213.410, F.A.C.	Rule 62-213.440, F.A.C.
Rule 62-296.320(4)(b)1., F.A.C.	Rule 62-296.320(4)(b)4.a., F.A.C.
Rule 62-297.310(2), F.A.C.	Rule 62-297.310(4)(a)2.c., F.A.C.
Rule 62-297.310(5), F.A.C.	Rule 62-297.310(7), F.A.C.
Rule 62-297.310(8), F.A.C.	Rule 62-297.401, F.A.C.
40 CFR 279 - Standards for the Management of Used oil	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **Simple cycle GT**	2. Emission Point Type Code: **3**	
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Emission Units 003-014 are 12 identical simple cycle gas turbines, regulated collectively**		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: **The 12 simple cycle gas turbines share a common APIS ID number: 52FTM360002.**		
5. Discharge Type Code: **V**	6. Stack Height: **32** feet	7. Exit Diameter: **11.4** feet
8. Exit Temperature: **975** °F	9. Actual Volumetric Flow **1,160,000** 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): **469660** North (km): **2952564**		
14. Emission Point Comment (limit to 200 characters): **Emission point UTM coordinates are for simple cycle GT 1. GTs 1-12 are regulated collectively as a bank of 12.**		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Gas turbine bank (1-12) burning distillate oil and on-specification used oil from FPL operations.**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **Thousand gallons burned**	
4. Maximum Hourly Rate: **67**	5. Maximum Annual Rate: **586,920**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash: **0.01**	9. Million Btu per SCC Unit: **136**
10. Segment Comment (limit to 200 characters): **Maximum Annual Rate provided in #5 above is based on 12 combustion turbines 8,760 hours/yr operation.** **Calculations:** **9,120mmbtu/hr / 136 mmbtu/kgal = 67 kgal/hr** **67kgal/hr * 8760 hours/yr = 586,920 kgal/yr**		

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOx			**EL**

G. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units -
Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions

1. Pollutant Emitted: **NOx**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **530** lb/hour **2,321** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **530 lb./hr** Reference: **Permit No. 0710002-007-AV**	7. Emissions Method Code: **3**
8. Calculation of Emissions (limit to 600 characters): **For Each CT** **(530 lb/hour) * (8,760 Hours/year) / 2,000 lb/ton = 2,321 tons per year**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions __1__ of __1__

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **530 lb/hr/turbine**	4. Equivalent Allowable Emissions: **530** lb/hour **2,321** tons/year
5. Method of Compliance (limit to 60 characters): **EPA method 7 or 7E incorporated by reference in Rule 62-204.800, F.A.C. and Permit No. 0710002-005-AC, Specific Condition No. 10**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emission rate based on turbine inlet of 59 degrees F.** **Test one CT each federal fiscal year.**	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation _1_ of _2_

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: **20** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **VE Test - EPA Method 9 if unit operates more than 400 hours/year**	
5. Visible Emissions Comment (limit to 200 characters): **See Permit No. 0710002-007-AV.**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units 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:	
5. Installation Date	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)

Visible Emissions Limitation: Visible Emissions Limitation _2_ of _2_

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested 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 (limit to 200 characters): **FDEP Rule 62-210.700(1). Allowed for 2 hours (120 minutes) per 24 hours for start-up, shutdown and malfunction**	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units 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:	
5. Installation Date	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: **PFMEU3_1.bmp** [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: **PFMU3_2.doc** [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [X] Attached, Document ID: **PFMU3_5** [ ] Previously submitted, Date: ________ [ ] Not Applicable
6. Procedures for Startup and Shutdown [X] Attached, Document ID: **PFMU3_6.doc** [ ] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID: ________ [X] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID: ________ [X] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
[ ] Attached, Document ID:________ [X] Not Applicable

12. Alternative Modes of Operation (Emissions Trading)
[ ] Attached, Document ID:________ [X] Not Applicable

13. Identification of Additional Applicable Requirements
[ ] Attached, Document ID:________ [X] Not Applicable

14. Compliance Assurance Monitoring Plan
[ ] Attached, Document ID:________ [X] Not Applicable

15. Acid Rain Part Application (Hard-copy Required)

[ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
Attached, Document ID:________

[ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
Attached, Document ID:________

[ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.)
Attached, Document ID:________

[ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)
Attached, Document ID:________

[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
Attached, Document ID:________

[ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.)
Attached, Document ID:________

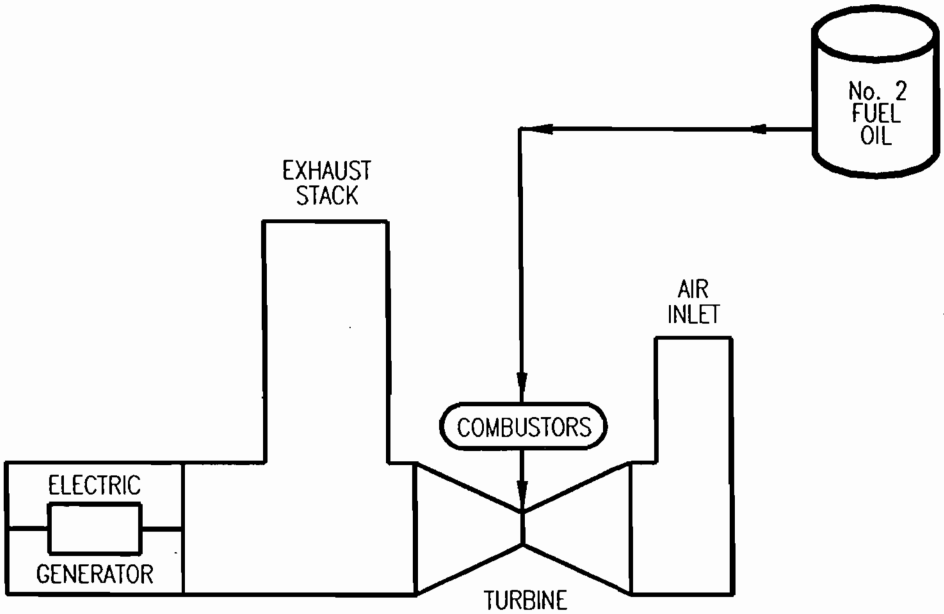
[X] Not Applicable

ATTACHMENT: PFMEU3_1.bmp

TECHNICAL ACCEPTANCE		
ENGINEERING ORGANIZATION		
ORG	BY	DATE

WALKDOWN INFORMATION		
AS-BUILT INFORMATION		
ORG	BY	DATE

BAR CODE



TYPICAL GT CONFIGURATION
GAS TURBINE UNITS 1 THRU 12

REV	DATE	REVISION DESCRIPTION	BY	CH	COR	APR	ORG
0	8/1/95	ISSUED FOR TITLE V PERMIT	PWB	PWB	CSP	CSP	ETS

SYSTEM: YY	DISCIPLINE: M	PLANT/UNIT: FT. MYERS PLANT
SCALE: N/A	CAD FILE NAME: FM001375	TITLE: EMISSION UNIT FLOW DIAGRAM GAS TURBINE UNITS 1 THRU 12 ATTACHMENT NO. EU3
DRAWING SIZE: A (8.5X11)	FPL ARCHIVE NAME: FM001375	

FPL

DRAWING NUMBER	SHEET	REV
PFM1-M0104-YY	1 OF 1	0

FPGSYM/FPGBDR-A 9/90

Attachment PFMU3_2.doc

Fuel Analysis
No. 2 Distillate oil (typical)[3]

Parameter	Typical value	Specifications
API gravity (@ 60 F)	35.0[2]	30 - 40[1]
Heat content (MBtu/bbl)	5,700 - 5,800[2]	none
% sulfur	0.3 - 0.5[1]	0.5 maximum[1]
% nitrogen	no specification	none
% ash	<0.01[2]	0.01[1]

Footnotes:
(1) Data taken from FPL fuel specifications.

(2) Data taken from laboratory analysis.

(3) The values are "typical" based upon the following:
- Information gathered by FPL through laboratory analysis, and
- FPL's fuel purchasing specifications. It should be noted that the analytical results obtained from grab samples taken at any given time may vary from those listed.

Attachment PFMU3_5

Compliance Test Report

The simple cycle Combustion Turbines (EU 003-014) are going through their compliance testing at the time of this application's submittal, therefore, the complete results of the testing will be forwarded to the Department under a separate cover.

Attachment PFMU3_6.doc

Procedures for Startup and Shutdown - Simple-Cycle Gas Turbines

The gas turbines do not currently employ any hardware for monitoring or control of emissions due to the fact that they are "peaking" units which have a combined annual capacity factor limitation of 10%. Therefore, the only method for determining excess emissions at present is visual (EPA Method 9 Opacity Readings).

All FPL operators undergo extensive training prior to operating FPL generating equipment. This training includes an overview of plant emission limits and best operational practices undertaken in the event excess emissions are encountered.

If excess emissions (e.g. opacity) are exhibited during startup of a gas turbine unit, corrective actions may include adjusting load rates, changing from automatic to manual operational control or shutting down the unit to investigate the cause of the opacity problem.

III. EMISSIONS UNIT INFORMATION

A separate Emissions Unit Information Section (including subsections A through J as required) must be completed for each emissions unit addressed in this Application for Air Permit. If submitting the application form in hard copy, indicate, in the space provided at the top of each page, the number of this Emissions Unit Information Section and the total number of Emissions Unit Information Sections submitted as part of this application.

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

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).

[X] 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. Regulated or Unregulated Emissions Unit? (Check one)

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

[X] The emissions unit addressed in this Emissions Unit Information Section is an unregulated emissions unit.

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters):
Unregulated emission units

4. Emissions Unit Identification Number: **XXX**
[ ] No ID
[ ] ID Unknown

5. Emissions Unit Status Code: **A**	6. Initial Startup Date: **JULY 1969 (Emer. Diesel Gen.)**	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [ ]

9. Emissions Unit Comment: (Limit to 500 Characters)

This emission unit information consists of the emergency diesel generator, diesel fire pump, unregulated tanks, exempt emission units and insignificant activities at the facility.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method):
2. Control Device or Method Code(s):

Emissions Unit Details

1. Package Unit: Manufacturer: **Detroit Diesel**	Model Number: **7124-3000**
2. Generator Nameplate Rating:	**0.5** MW
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

B. EMISSIONS UNIT CAPACITY INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		**3.128**	mmBtu/hr
2. Maximum Incineration Rate:	lb/hr		tons/day
3. Maximum Process or Throughput Rate:			
4. Maximum Production Rate:			
5. Requested Maximum Operating Schedule:			
	hours/day		days/week
	weeks/year	**400**	hours/year

6. Operating Capacity/Schedule Comment (limit to 200 characters):

Information provided above is for the emergency diesel generator, which will be limited to 400 hours per year of operation. Other emission units addressed in this section may operate up to 8,760 hours/year.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment PFMFS_12	

D. EMISSION POINT (STACK/VENT) INFORMATION
(Regulated Emissions Units Only)

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **Unregulated emission units**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **H**	6. Stack Height: **12** feet	7. Exit Diameter: **0.5** feet
8. Exit Temperature: **950** °F	9. Actual Volumetric Flow Rate: **2,970** 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): **469.835** North (km): **2952.855**	
14. Emission Point Comment (limit to 200 characters): **Information provided is for the emergency diesel generator. Information on other emission units addressed in this section may vary.**	

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 1 of 9

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Diesel fuel burned in the emergency diesel generator.**		
2. Source Classification Code (SCC): **2-01-001-02**	3. SCC Units: **Thousand gallons burned**	
4. Maximum Hourly Rate: **0.023**	5. Maximum Annual Rate: **9.2**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **136**
10. Segment Comment (limit to 200 characters): **The maximum annual rate is calculated based upon 400 hours per year of operation.**		

Segment Description and Rate: Segment 2 of 9

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Above ground tank #M2**		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): **Formerly the Unit #2 Fuel Oil Metering Tank. As a result of the repowering, this tank has been emptied of oil, cleaned and is now a water storage tank.**		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 3 of 9

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Above ground tank #M1B**		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): **As a result of the repowering, this tank was drained, cleaned and is no longer intended for petroleum service.**		

Segment Description and Rate: Segment 4 of 9

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Above ground tank # M1A**		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): **Formerly the Unit #1 Fuel Oil Day Tank. As a result of the repowering, this tank was drained, cleaned and is in service as a water tank.**		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 5 of 9

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Above ground tank #T1 – Working and breathing loss** **Formerly a #6 Fuel Oil Storage Tank. As a result of the repowering, this tank was converted to distillate oil service for the bank of 12 gas turbines.**		
2. Source Classification Code (SCC): **4-03-010-21**	3. SCC Units: **Thousand gallons transferred or handled**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor: **586,920**
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **136**
10. Segment Comment (limit to 200 characters): **Breathing loss = 4263.62 lbs VOC/yr (per EPA Tanks 2 program)** **Working loss = 11,927.56 lbs VOC/yr (per EPA Tanks 2 program)** **Total estimated losses = 8.09 TPY, using estimated activity factor given above**		

Segment Description and Rate: Segment 6 of 9

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Above ground tank #T2 – Working and breathing loss** **Formerly a #6 Fuel Oil Storage Tank. As a result of the repowering, this tank was converted to distillate oil service for the bank of 12 gas turbines.**		
2. Source Classification Code (SCC): **4-03-010-21**	3. SCC Units: **Thousand gallons transferred or handled**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor: **586,920**
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **136**
10. Segment Comment (limit to 200 characters): **Breathing loss = 4263.62 lbs VOC/yr (per EPA Tanks 2 program)** **Working loss = 11,927.56 lbs VOC/yr (per EPA Tanks 2 program)** **Total estimated losses = 8.09 TPY, using estimated activity factor given above**		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 7 of 9

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Above ground tank #T3**		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): **Formerly a Distillate Oil Storage Tank for the bank of 12 gas turbines. As a result of the repowering, this tank was drained, cleaned, relocated, and is used for water storage.**		

Segment Description and Rate: Segment 8 of 9

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Above ground tank #T4**		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): **Formerly a Distillate Oil Storage Tank for the bank of 12 gas turbines. As a result of the repowering, this tank was drained, cleaned, dismantled and removed from the site.**		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(All Emissions Units)

Segment Description and Rate: Segment 9 of 9

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Above ground tank # unleaded**		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): **Formerly an Unleaded Gasoline Storage Tank. As a result of the repowering, this tank was drained, cleaned, and is no longer intended for petroleum product service.**		

Segment Description and Rate: Segment _____ of _____

1. Segment Description (Process/Fuel Type) (limit to 500 characters):		
2. Source Classification Code (SCC):	3. SCC Units:	
4. Maximum Hourly Rate:	5. Maximum Annual Rate:	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters):		

J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [X] Attached, Document ID: **Attachment No. FS-3** [ ] Not App. [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: **PFMU4_2.doc** [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [ ] Attached, Document ID: ________ [ ] Previously submitted, Date: ____________ [X] Not Applicable
6. Procedures for Startup and Shutdown [X] Attached, Document ID: **PFMU4_6.doc** [ ] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID: ________ [X] Not Applicable
9. Other Information Required by Rule or Statute [X] Attached, Document ID: **Attachment PFM-FW2** [ ] Not Applicable
10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:________ [X] Not Applicable
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [X] Not Applicable
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [X] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [X] Not Applicable
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:________ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [X] Not Applicable

Attachment PFMU4_2.doc

Fuel Analysis
No. 2 Distillate oil (typical)[3]

Parameter	Typical value	Specifications
API gravity (@ 60 F)	35.0[2]	30 - 40[1]
Heat content (MBtu/bbl)	5,700 - 5,800[2]	none
% sulfur	0.3 - 0.5[1]	0.5 maximum[1]
% nitrogen	no specification	none
% ash	<0.01[2]	0.01[1]

Footnotes:

(1) Data taken from FPL fuel specifications.

(2) Data taken from laboratory analysis.

(3) The values are "typical" based upon the following:
- Information gathered by FPL through laboratory analysis, and
- FPL's fuel purchasing specifications. It should be noted that the analytical results obtained from grab samples taken at any given time may vary from those listed.

Attachment PFMU4_6.doc

Procedures for Startup / Shutdown

The emergency diesel generator is the main backup emergency electrical power supply component for the fossil generating units. The function of the emergency diesel generator is to supply electric power to key power plant equipment during emergency loss-of-power situations. This equipment is typically test-run on a monthly basis for 1 to 2 hours to ensure that it will function properly when needed in an emergency.

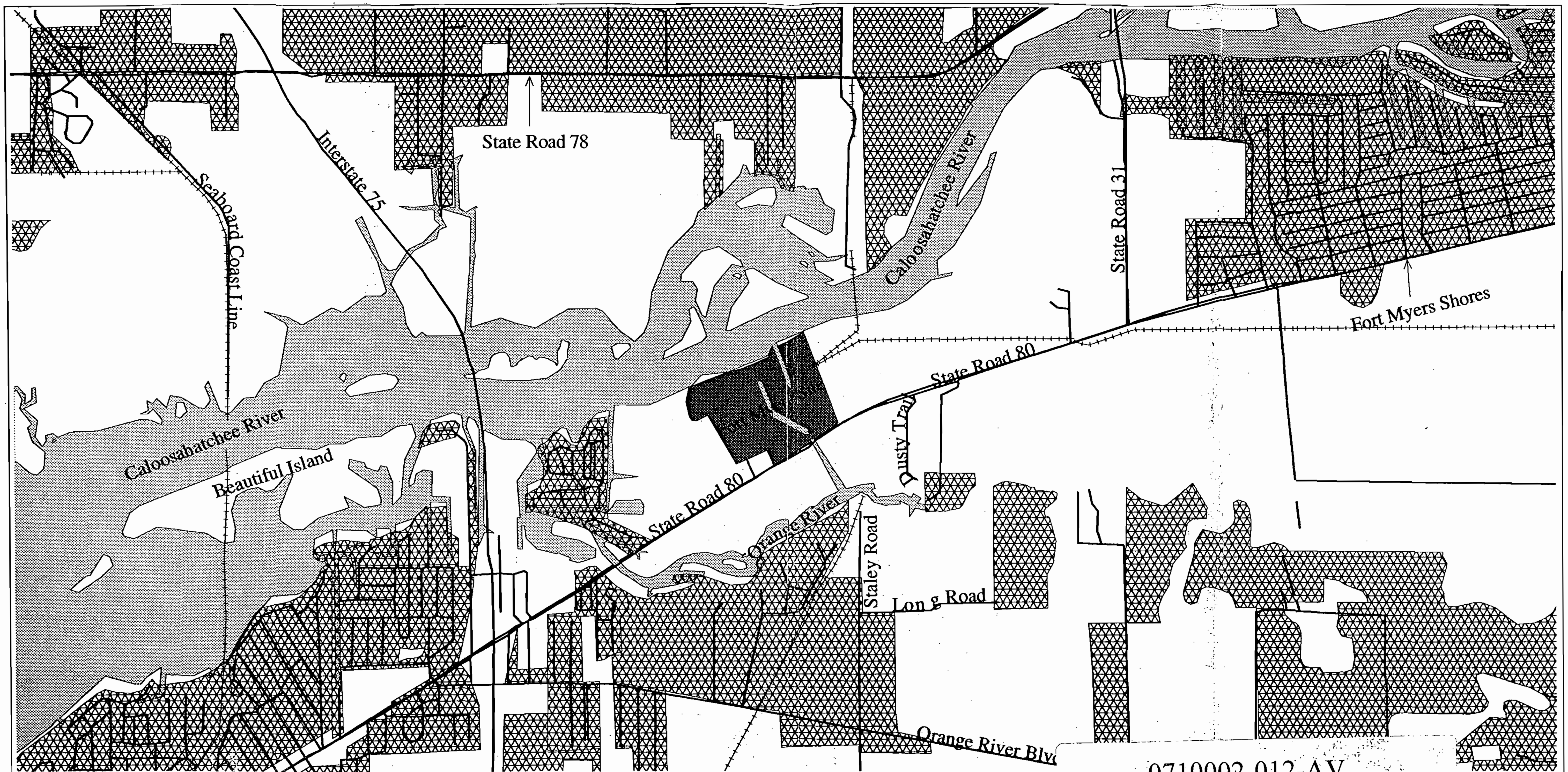
Startup for the emergency diesel generator begins with actuating a switch which operates an electric motor on the diesel engine which "turns over" the diesel engine until ignition of the diesel fuel commences.

Shutdown is performed when the normal electric power supply to plant equipment is restored. Shutdown is performed by shutting off the diesel fuel supply to the emergency diesel generator.

Best Operating Practices include proper maintenance of the diesel engines by trained personnel on the generating unit in accordance with manufacturer specifications, and the purchase of diesel fuel that also meets specifications.

If excess emissions are suspected during operation of the emergency diesel generator, appropriate measures to minimize the duration of the event may include shutting down the equipment and investigating the cause of the opacity.

BEST AVAILABLE COPY



Fort Myers Plant Area Map
Lee County

Source: Landuse data provided by South Florida Water Management District (1993)

No expressed or implied warranties including, but not limited to the implied warranties of MERCHANTABILITY OF FITNESS FOR A PARTICULAR PURPOSE are made. The materials contained herein are provided 'as is' and may contain inaccuracies and user is warned to utilize the material's accuracy independently and assumes the risk of any and all loss.

FPL Environmental Affairs

0km 1km 2km

0mi 1mi

S

0710002-012-AV

2/26/07

ite

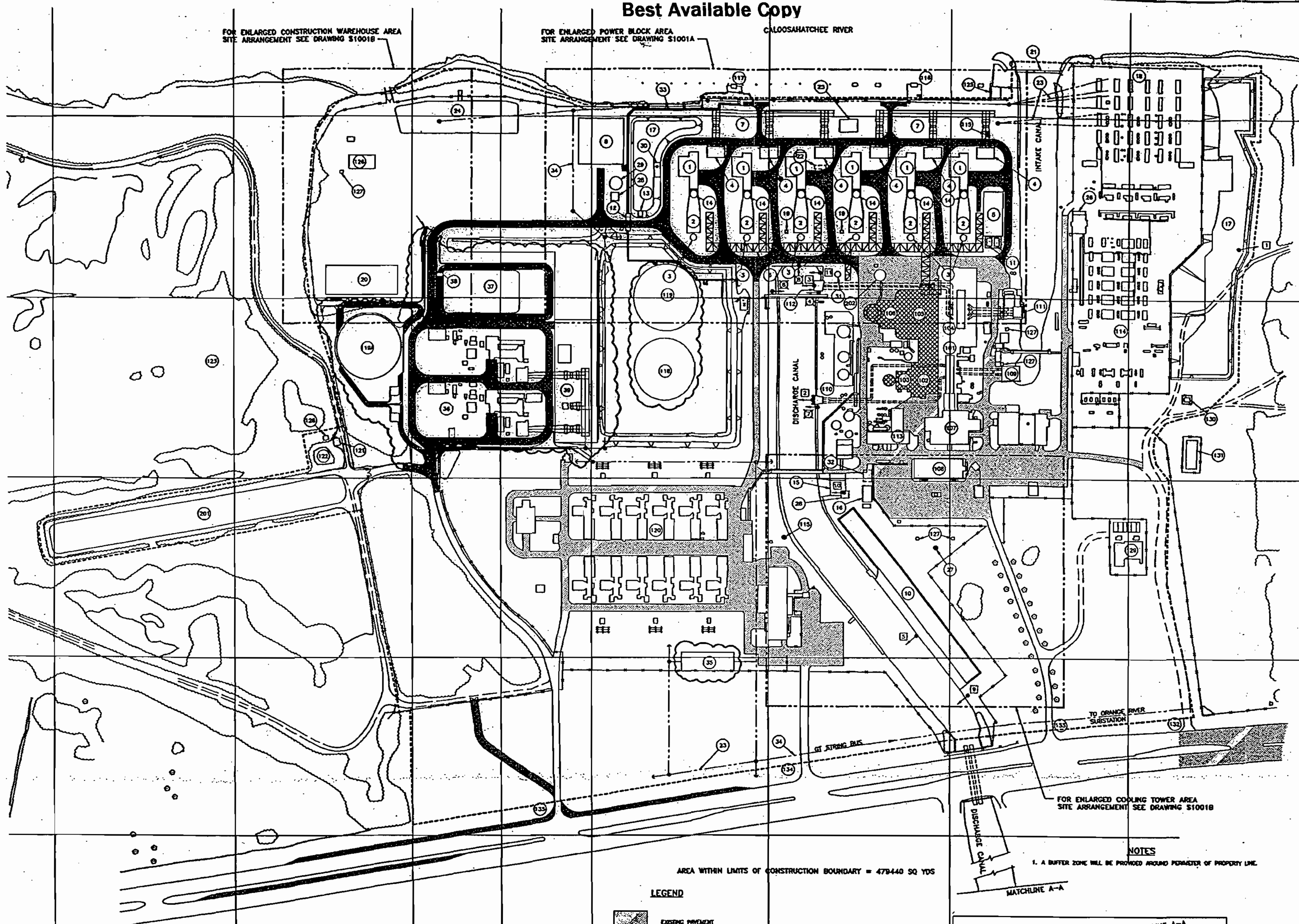
Residential Areas

Major Roads

Railroads

/export/home/ron/maps/pfm-site.map (8-95)

Best Available Copy



NEW FACILITY LEGEND

1. COMBUSTION TURBINE
2. HEAT RECOVERY STEAM GENERATOR (HRSG)
3. STACK
4. TRANSFORMER
5. CONTROL/ELECTRICAL BUILDING
6. PIPE RACK
7. CT SWITCHYARD
8. GAS METER STATION
9. NOT USED
10. COOLING TOWER
11. STATION SERVICE TRANSFORMERS NO. A & B
12. FUEL OIL PIPE TRENCH
13. STORMWATER LIFT STATION
14. BY-PASS STACK
15. COOLING TOWER INTAKE STRUCTURE
16. COOLING TOWER ELECTRICAL ENCLOSURE
17. DRY DETENTION AREA
18. SWITCHYARD EXPANSION
19. HOT DRAIN SUMP
20. CONSTRUCTION WAREHOUSE
21. OPTIONAL WATER MIXING STRUCTURE
22. OIL WATER SEPARATOR
23. REROUTE OF GT TRANSMISSION LINE BY FPL
24. DETENTION POND
25. CT RELAY VAULT
26. RELAY VAULT ADDITION
27. NEW WELL
28. FIRE WATER PUMP ENCLOSURE
29. FIRE WATER STORAGE TANK
30. LIQUID HYDROGEN STORAGE TANK & FILL STATION
31. CONDENSATE STORAGE TANK
32. FUTURE CHEMICAL FEED EQUIPMENT AREA
33. RELOCATED NO. 2 & NO. 6 FUEL OIL PIPING
34. ROUTE OF SIMPLE CYCLE TRANSMISSION LINE
35. FPL POWER DELIVERY SUBSTATION
36. SIMPLE CYCLE COMBUSTION TURBINE AREA
37. STORMWATER DETENTION AREA
38. STORMWATER LIFT STATION
39. SIMPLE CYCLE CT SWITCHYARD

EXISTING FACILITY LEGEND

101. UNIT 1 TURBINE GENERATOR
102. UNIT 1 BOILER STRUCTURE
103. UNIT 1 STACK
104. UNIT 2 TURBINE GENERATOR
105. UNIT 2 BOILER STRUCTURE
106. UNIT 2 STACK
107. SERVICE BUILDING
108. ADMINISTRATIVE BUILDING
109. UNIT 1 INTAKE STRUCTURE
110. UNIT 1 DISCHARGE STRUCTURE
111. UNIT 2 INTAKE STRUCTURE
112. UNIT 2 DISCHARGE STRUCTURE
113. WATER TREATMENT AREA
114. SWITCHYARD
115. MANATEE WELL (REMOVED)
116. NO. 2 FUEL OIL UNLOADING DOCK
117. NO. 6 FUEL OIL UNLOADING DOCK
118. NO. 6 FUEL OIL STORAGE TANK CONVERTED TO NO. 2 FUEL OIL STORAGE
119. RELOCATED NO. 2 FUEL OIL STORAGE TANK
119A. RELOCATED TANK CONVERTED TO WATER STORAGE
120. GAS TURBINE AREA
121. STORMWATER FORWARDING SUMP
122. STORMWATER COLLECTION BASIN
123. EVAPORATION / PERCOLATION AREA
124. NOT USED
125. BOAT HOUSE
126. PAVILION
127. INTERMEDIATE AQUIFER WELL
128. ORGANO-CLAY OIL SEPARATOR
129. TICE SUBSTATION
130. FPL FIBER OPTIC BUILDING
131. SPRINT FIBER OPTIC BUILDING
132. GATE 1 (SUBSTATION ENTRANCE)
133. GATE 2 (MAIN ENTRANCE)
134. GATE 3 (CT ENTRANCE)
135. GATE 4 (PAVILION ENTRANCE)

REVISED FACILITY LEGEND

201. EXISTING ASH SETTLING BASIN TO BE CONVERTED TO STORMWATER DETENTION BASIN
202. EXISTING CONDENSATE STORAGE TANK TO BE CONVERTED TO CYCLE MAKEUP TANK

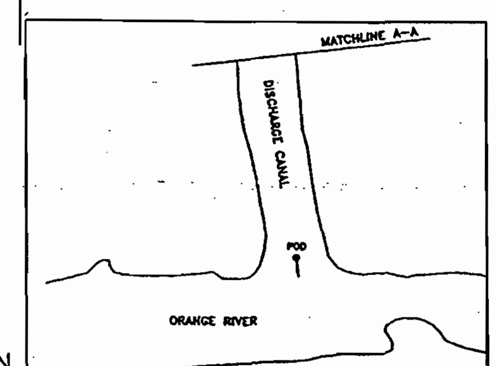
NOTES

1. A BUFFER ZONE WILL BE PROVIDED AROUND PERIMETER OF PROPERTY LINE.

LEGEND

- EXISTING PAVEMENT
- NEW PAVEMENT
- PAVED ROADS FOR ADDITIONAL UNITS
- FACILITIES TO BE DEMOLISHED
- POD POINT OF DISCHARGE
- LIMITS OF CONSTRUCTION
- OUTFALL
- OUTFALL ABANDONED AFTER REPOWERING

OUTFALL		STATE PLANE COORDINATE
1	SWITCHYARD STORMWATER	N 859031.53 E 728200.44
2	UNIT 1 CIRCULATING WATER	N 859079.40 E 727278.33
3	UNIT 2 CIRCULATING WATER	N 858372.15 E 727156.81
4	UNIT 2 BOILER BLOWDOWN	
5	COOLING TOWER	N 858567.40 E 727765.31
6	MANATEE WELL	
7	UNIT 1 BOILER BLOWDOWN	
8	CW INTAKE SCREEN WASH WATER – UNIT 2	
9	CW INTAKE SCREEN WASH WATER – UNITS 1 & 2	N 858498.35 E 727994.57
10	DIESEL FIRE WATER PUMP TESTING	N 858875.39 E 727455.04
11	OPEN COOLING WATER	N 859411.40 E 727157.19



NOT TO BE USED FOR CONSTRUCTION

PFMFS_2.tif

REV	DATE	REVISIONS AND RECORD OF ISSUE
9	05/04/01	REVISED FOR PERMITTING
8	7/28/00	REVISED FOR LEE COUNTY DEVELOPMENT ORDER
7	09-17-99	GENERAL REVISIONS
6	07-02-99	RELEASED FOR CONSTRUCTION
5	05-21-99	GENERAL REVISIONS
4	04-07-99	REVISED FOR LEE COUNTY DEVELOPMENT ORDER
3	03-10-99	ISSUED FOR PERMIT
2	02-02-99	REVISED FOR IWW PERMIT
1	01-05-99	REVISED FOR LEE COUNTY DEVELOPMENT ORDER
0	09-24-98	ISSUED FOR LEE COUNTY DEVELOPMENT ORDER

22°37'51" PLANT STATE PLANE N

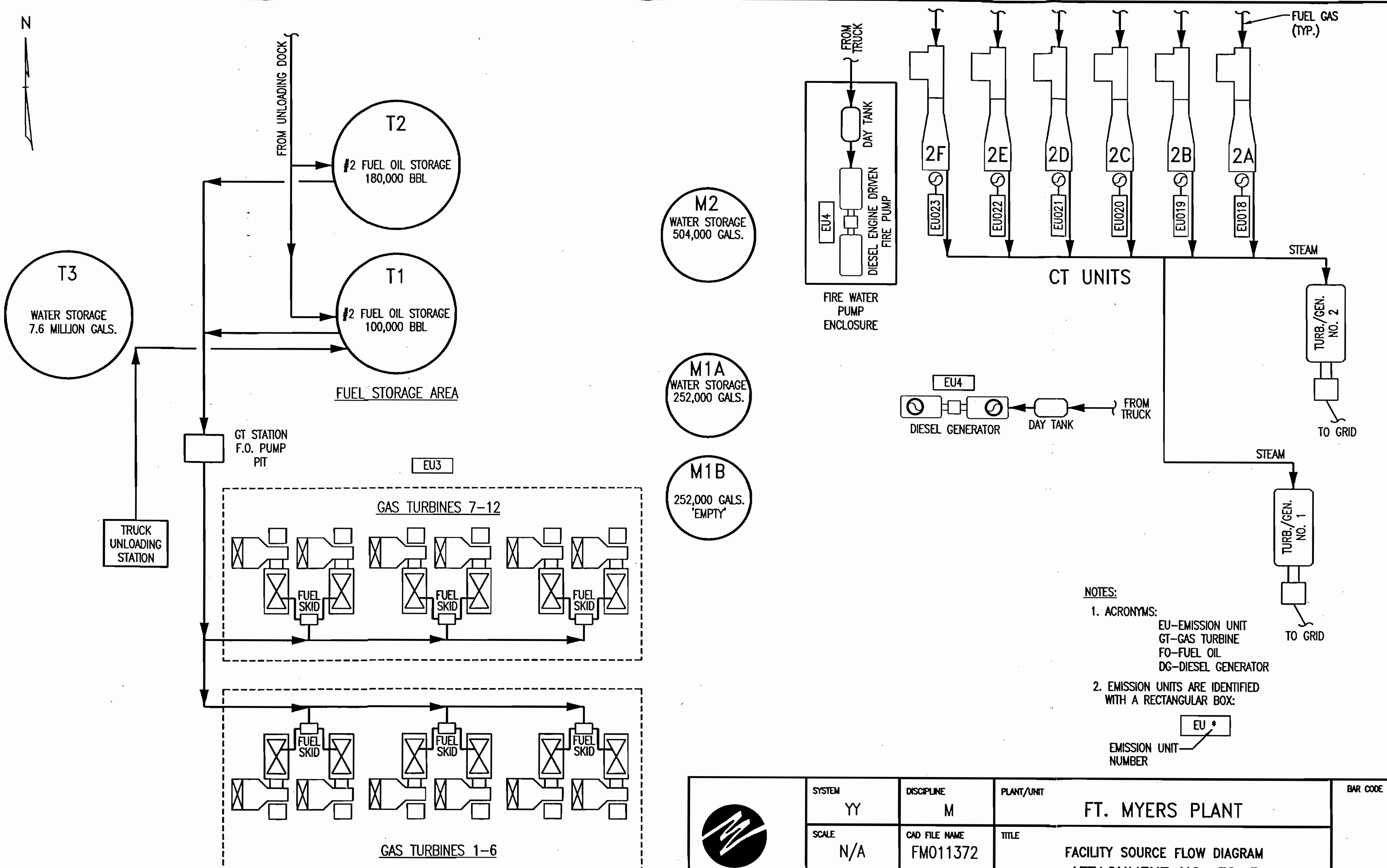
100' 50' 0 100' 200' 1"=100'

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA. SIGNED EDWARD S. BOCHICK DATE REG NO. 47248

BLACK & VEATCH LLP ENGINEER ESK DRAWN CDK CHECKED DATE 07-02-99

FLORIDA POWER & LIGHT CO.
FORT MYERS REPOWERING PROJECT
GENERAL – SITE
OVERALL SITE ARRANGEMENT

PROJECT 59662-9STU-S1001 REV 9
SP-001



NOTES:

1. ACRONYMS:
   - EU-EMISSION UNIT
   - GT-GAS TURBINE
   - FO-FUEL OIL
   - DG-DIESEL GENERATOR
2. EMISSION UNITS ARE IDENTIFIED WITH A RECTANGULAR BOX:

EU #

EMISSION UNIT NUMBER

WALKDOWN INFORMATION			
AS-BUILT INFORMATION	ORG	BY	DATE

TECHNICAL ACCEPTANCE			
ENGINEERING ORGANIZATION	ORG	BY	DATE

SCALE 3/8" = 1'-0" (0 1 2 3 4 5)

SCALE 1/4" = 1'-0" (0 1 2 3 4 5)

REV	DATE	REVISION DESCRIPTION	BY	CH	COR	APR	ORG
1	6/25/02	CAD REDRAWN TO INCORPORATE REPOWER MODIFICATIONS	ELV	SD	CSP	CSP	PGD
0	8/1/95	ISSUED FOR TITLE V PERMIT	PWB	PWB	CSP	CSP	ETS

FPL

SYSTEM: YY	DISCIPLINE: M	PLANT/UNIT: FT. MYERS PLANT	BAR CODE
SCALE: N/A	CAD FILE NAME: FM011372	TITLE: FACILITY SOURCE FLOW DIAGRAM ATTACHMENT NO. FS-3 TITLE V	
DRAWING SIZE: B(11"X17")	FPL ARCHIVE NAME: FM011372		
DRAWING NUMBER: PFM1-M0101-YY		SHEET: 1 OF 1	REV: 1

GSYM/FPGBDR-B 5/93

Kofax Separator Application 0710002-012-AV