H. D. KING POWER PLANT
311 North Indian River Drive
Fort Pierce, Florida 34950
(772) 464-5792

July 9, 2002

Mr. Scott M. Sheplak, P.E.
Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation, Title V Section
Mail Station 5505
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Subject: **Title V Renewal Application**
Fort Pierce Utilities Authority
H.D. King Power Plant

4

Dear Mr. Sheplak:

Enclosed please find three additional copies of the Application for Renewal of Title V Permit No. 1110003-004-AV for the Fort Pierce Utilities Authority H.D. King Power Plant.

If you have any questions concerning this application, please contact me at 772-466-1600, ext. 5058 or by email esl@fpua.com.

Sincerely,

Edward S. Leongomez
Superintendent of Power Generation

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H. D. KING POWER PLANT
311 North Indian River Drive
Fort Pierce, Florida 34950
(772) 464-5792

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JUL 08 2002
BUREAU OF AIR REGULATION

July 2, 2002

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, FL 32399-2400

Subject: Title V Renewal Application
Fort Pierce Utilities Authority
H.D. King Power Plant

Dear Sir or Madam:

Enclosed please find an Application for Renewal of Title V Permit No. 1110003-004-AV for the Fort Pierce Utilities Authority H.D. King Power Plant. In accordance with Florida Department of Environmental Protection's ("FDEP") requirements for Title V Reapplications, a complete set of application forms, both hard copy and electronic, is being submitted. The H.D. King Facility is located in St. Lucie County and consists of three gas/diesel-fired boilers and one combined-cycle gas turbine.

The following changes from the current Title V permit are requested and are reflected in the application materials, as appropriate.

- remove the PM emission limit for natural gas firing for Units 7 and 8;
- remove the VOC testing requirement for Units 7 and 8 when firing natural gas, provided that CO emissions are in compliance;
- sources E.U. 009 (Cooling Tower) and E.U. 010 (General Purpose Internal Combustion Engines) are now listed as insignificant emissions units;
- the listed heat input for Unit 8 now reflects the manufacturer's design limit of 644 mmBtu/hr; and

- it is requested that the span value for NOx listed in Item D37 of the current Title V permit for Unit 8 be changed to reflect a range of zero – 250 ppm.

If you have any questions concerning this application, please contact me at 772-466-1600, ext. 5058 or by email esl@fpua.com.

Sincerely,
Fort Pierce Utilities Authority

Edward S. Leongomez
Superintendent of Power Generation

Enclosure

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

See Instructions for Form No. 62-210.900(1)

I. APPLICATION INFORMATION

Identification of Facility

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

Application Contact

1. Name and Title of Application Contact: Edward S. Leongomez, Superintendent/Power Generation
2. Application Contact Mailing Address: Organization/Firm: Fort Pierce Utilities Authority Street Address: 311 North Indian River Drive City: Fort Pierce State: FL Zip Code: 34950
3. Application Contact Telephone Numbers: Telephone: (772)- 464-5792 Fax: (772)- 465-7596

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	7-8-02
2. Permit Number:	1110003-005-AV
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

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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:__1110003-004-AV__________________

Reason for revision:___Renewal_______________________________________

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: Thomas W. Richards, P.E., Director of Electric System
2. Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: Fort Pierce Utilities Authority Street Address: P.O. Box 3191 City: Fort Pierce State: FL Zip Code: 34948
3. Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: (772)- 466-1600 ext. 3400 Fax: (772)- 595-9841
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.* Signature Date 07/03/02

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name: Ivan L. Clark Registration Number: 49777 (FL)
2. Professional Engineer Mailing Address: Organization/Firm: R.W. Beck, Inc. Street Address: 1125 17th Street, Suite 1900 City: Denver State: CO Zip Code: 80202-2615
3. Professional Engineer Telephone Numbers: Telephone: (303)- 299-5200 Fax: (303)- 297-2811

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] June 27, 2002

Signature Date

(seal) IVAN L. CLARK CERTIFICATE NO. 0045777 STATE OF FLORIDA REGISTERED ENGINEER

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
001	2.75 MW West Diesel #1		
002	2.75 MW East Diesel #2		
003	31.6 MW Combined Cycle Gas Turbine Unit #9		
004	16.5 MW Boiler Unit #6		
007	37.5 MW Boiler Unit #7		
008	56.1 MW Boiler Unit #8		

Application Processing Fee

Check one: [ ] Attached - Amount: $________________ [✓] 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

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: 17 East (km): 566.79 North (km): 3036.30			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): 27 27 0 Longitude (DD/MM/SS): 80 19 26			
3. Governmental Facility Code: 4	4. Facility Status Code: A	5. Facility Major Group SIC Code: 49	6. Facility SIC(s):
7. Facility Comment (limit to 500 characters): The facility is an electric power plant. It consists of two 2.75-MW diesel-electric generating units, one16.5-MW steam-electric unit, one 37.5-MW steam-electric unit, one 56.1-MW steam-electric unit, and one 31.6-MW combined cycle gas turbine (23.4-MW turbine and 8.2-MW heat recovery steam generator (HRSG). The combined cycle gas turbine is not an Acid Rain affected unit, as the HRSG is not supplementally fired.			

Facility Contact

1. Name and Title of Facility Contact: Edward S. Leongomez, Superintendent/Power Generation		
2. Facility Contact Mailing Address: Organization/Firm: Fort Pierce Utilities Authority Street Address: 311 North Indian River Drive City: Fort Pierce	State: FL	Zip Code: 34950
3. Facility Contact Telephone Numbers: Telephone: (407)- 464-5792	Fax: (407)- 465-7596	

Facility Regulatory Classifications

Check all that apply:

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

List of Applicable Regulations

40CFR60.7 - Notification and Recordkeeping (NSPS)	40CFR60.8 – Performance Tests (NSPS)
40CFR60.11 – Compliance with Standards and Maintenance Requirements (NSPS)	40CFR60.12 – Circumvention (NSPS)
40CFR60.13 – Monitoring Requirements (NSPS)	40CFR60 – Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators (NSPS)
40CFR60 – Subpart GG – Standards of Performance for Stationary Gas Turbines (NSPS)	40CFR70 – State Operating Permits
40CFR72 – Regulations on Permits	40CFR73 – SO2 Allowance System
40CFR75 – Regulations for CEMs under Acid Rain Requirements	40CFR77 – Excess Emissions for Acid Rain Units
40CFR78 – Appeal Procedures for Acid Rain Units	40CFR60.19 – General Notification and Reporting Requirements

List of Applicable Regulations

62-4.001 through 62-4.160, FAC – Permits Part I General	62-4.210, FAC – Construction Permits
62-4.220, FAC – Operating Permits	62-103.150, FAC – Public Notice of Application and Proposed Agency Action
62-210, FAC – Stationary Sources	62-212.300, FAC – Sources not Subject to PSD or Nonattainment Requirements
62-213, FAC – Operation Permits for Major Sources of Air Pollution (Title V)	62-272.300, FAC – Ambient Air Quality Standards
62-273, FAC – Air Pollution Episodes	62-296.310(2)(a), FAC – General Visible Emission Standards
62-296.310(3), FAC- Unconfined Emissions of Particulate Matter	62-296.320(2), FAC – General Pollutant Emission Limiting Standards, Objectionable Odors
62-296.330, FAC – Best Available Control Technology	62-296.405(1), FAC – Specific Emissions Limiting & Performance Stds for Existing Foss. Fuel Steam Gen. >250 MMBtu/hr
62-296.800, FAC – New Source Performance Standards	62-297.310 through 62-297.400, FAC- Compliance Test Requirements
62-297.500(1), FAC – Continuous Emissions Monitoring Requirements	62.297.570, FAC – Compliance Test Reports

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: Figure 1 [ ] Not Applicable [ ] Waiver Requested
2. Facility Plot Plan: [X] Attached, Document ID: Figure 2 [ ] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [X] Attached, Document ID: Figures 3-8 [ ] Not Applicable [ ] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [X] Attached, Document ID: ftpcpart.wk4 [ ] Not Applicable [ ] Waiver Requested
5. Fugitive Emissions Identification: [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [ ] Attached, Document ID:________ [X] Not Applicable
7. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [X] Attached, Document ID: ftpinsig.wk4 [ ] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [X] Attached, Document ID:ftp_cfcs.wk4 [ ] Equipment/Activities On site but Not Required to be Individually Listed [ ] Not Applicable
10. Alternative Methods of Operation: [X] Attached, Document ID:ftpcaltm.wk4 [ ] 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: Attachment F[ ] 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:ftpccomp.wk4 [ ] Not Applicable
15. Compliance Certification (Hard-copy Required): [X] Attached, Document ID: Attachment A [ ] Not Applicable

FORT PIERCE UTILITIES AUTHORITY POWER PLANT
Precautions to Prevent Emissions of Unconfined Particulate Matter

The only potential source of unconfined particulate emissions is from vehicular traffic. Precautions to prevent and control unconfined emissions consist of paved fuel delivery roads and parking lots.

FORT PIERCE UTILITIES AUTHORITY POWER PLANT
LIST OF INSIGNIFICANT ACTIVITIES/UNITS

ACTIVITY/UNIT	RATIONALE FOR INSIGNIFICANCE
I.C. Engine - ~10 hp gasoline fired pump	Exempt pursuant to Rule 62-210.300(a)(21), FAC
I.C. Engine - ~ 5 hp gasoline fired pump	Exempt pursuant to Rule 62-210.300(a)(21), FAC
I.C. Engine - 65 hp MW Murphy diesel pump	Exempt pursuant to Rule 62-210.300(a)(21), FAC
I.C. Engine - ~16 hp gas powered portable welder	Exempt pursuant to Rule 62-210.300(a)(16), FAC
I.C. Engine - 11 hp gasoline fired power washer	Exempt pursuant to Rule 62-210.300(a)(21), FAC
No. 2 Fuel Oil Storage Tank #5 - 922,901 gallons	Low vapor pressure; Potential VOC emissions 1036 lbs/yr
Waste Oil Storage Tank	Very low vapor pressure
Compressed nitrogen bottles	No emissions
Unit 8 Cooling Tower	DEP presumptive exemption
Storage & use of chemicals solely for water treatment	Very low vapor pressures and small quantities/DEP presumptive exemption
55 gallon drum trichloroethylene and Perchloroethylene	Very low vapor pressures and small quantities/DEP presumptive exemption
Lube Oil Storage Area	Oil stored in closed 55 gallon drums; No emissions
Parts Washer (aliphatic hydrocarbon solvent)	Exempt pursuant to Rule 62-210.300(a)(26), FAC
Miscellaneous painting activities	Exempt pursuant to Rule 62-210.300(a)(23)(24), FAC
Miscellaneous welding activities	Exempt pursuant to Rule 62-210.300(a)(16), FAC
Oil/Water Separator	Very low vapor pressures; No emissions
Periodic fuel oil tank cleaning	Infrequent cleaning and low vapor pressure
General Purpose Internal Combustion Engines	Exempt pursuant to Rule 62-210.300(a)(21), FAC

FORT PIERCE POWER PLANT
List of Equipment/Activities Regulated under Title VI

Equipment that contains more than 50 lbs of charge of any Class I or Class II ozone-depleting substance regulated under Title VI of the CAA:

1) Office Air Conditioner - York 30 tons, contains 180 lbs R22

FORT PIERCE UTILITIES AUTHORITY
ALTERNATIVE METHODS OF OPERATION - UNITS 6 THROUGH 9

UNIT 6

Alternative Method #1: Unit 6 will fire 100 percent natural gas

Alternative Method #2: Unit 6 will fire 100 percent residual No. 2 fuel oil

Alternative Method #3: All units will fire a mixture of Natural Gas and Fuel oil Normally in 25% increments.

UNIT 7

Alternative Method #1: Unit 7 will fire 100 percent natural gas

Alternative Method #2: Unit 7 will fire 100 percent residual No. 2 fuel oil

Alternative Method #3: All units will fire a mixture of Natural Gas and Fuel oil Normally in 25% increments.

UNIT 8

Alternative Method #1: Unit 8 will fire 100 percent natural gas

Alternative Method #2: Unit 8 will fire 100 percent residual No. 2 fuel oil

Alternative Method #3: All units will fire a mixture of Natural Gas and Fuel oil Normally in 25% increments.

UNIT 9

Alternative Method #1: Unit 9 will fire 100 percent natural gas

Alternative Method #2: Unit 9 will fire 100 percent distillate No. 2 fuel oil

Alternative Method #3: All units will fire a mixture of Natural Gas and Fuel oil Normally in 25% increments.

FORT PIERCE UTILITIES AUTHORITY POWER PLANT
Compliance Report and Plan

Each emissions unit (diesel units 1&2, boilers 6, 7 & 8, and combined cycle unit 9) is in full compliance with each applicable federal, state and local regulation, as detailed under Subsection III-B. Emissions Unit Regulations and with all additional applicable requirements (compliance with current operating permits No. AO 56-175955 and AO 56-190275) as detailed under Subsection III-B. Emissions Unit Supplemental Information.

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
(2.75 MW West Diesel #1)

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)

[ ] 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):

2.75 MW West Diesel #1

4. Emissions Unit Identification Number: ID: 001 — [ ] 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	1/3/70	49	[N]

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

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
(2.75 MW East Diesel #2)

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)

[ ] 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):

2.75 MW East Diesel #2

4. Emissions Unit Identification Number: ID: 002 — [ ] 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	1/3/70	49	[N]

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

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
(31.6 MW Combined Cycle Gas Turbine Unit #9)

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):

31.6 MW Combined Cycle Gas Turbine Unit #9

4. Emissions Unit Identification Number: ID: 003

[ ] 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	1/1/89	49	[N]

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

The maximum output of the gas turbine is dependent upon the ambient temperature and is approximately 23.4 MW. The HRSG steam output supplies an 8.2 MW turbine generator. Because the gas turbine is less than 25-MW and the HRSG is not supplementally fired, the unit is not an acid rain unit.

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
(16.5 MW Boiler Unit #6)

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):

16.5 MW Boiler Unit #6

4. Emissions Unit Identification Number: ID: 004 — [ ] 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	1/4/58	49	[N]

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

The generating unit has a nameplate rating of 16.5 MW.

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
(37.5 MW Boiler Unit #7)

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):

37.5 MW Boiler Unit #7

4. Emissions Unit Identification Number: [ ] No ID
ID: 007 [ ] ID Unknown

5. Emissions Unit Status Code:	6. Initial Startup Date:	7. Emissions Unit Major Group SIC Code:	8. Acid Rain Unit?
A	1/5/64	49	[Y]

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

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
(56.1 MW Boiler Unit #8)

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):

56.1 MW Boiler Unit #8

4. Emissions Unit Identification Number: ID: 008

[ ] 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	1/4/76	49	[Y]

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

The model number of the unit is unavailable, however, the serial number is 706189.

Emissions Unit Control Equipment – (2.75 MW West Diesel #1)

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: General Motors Corporation	Model Number: MP-45
2. Generator Nameplate Rating: 3 MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

Emissions Unit Control Equipment - (2.75 MW East Diesel #2)

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: General Motors Corporation	Model Number: MP-45
2. Generator Nameplate Rating: 3 MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

Emissions Unit Control Equipment – (31.6 MW Combined Cycle Gas Turbine Unit #9)

1. Control Equipment/Method Description (Limit to 200 characters per device or method): Steam Injection for NOx control
2. Control Device or Method Code(s): 28

Emissions Unit Details

1. Package Unit: Manufacturer: General Electric	Model Number: 295352
2. Generator Nameplate Rating: 32 MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

Emissions Unit Control Equipment – (16.5 MW Boiler Unit #6)

1. Control Equipment/Method Description (Limit to 200 characters per device or method): Multiple Cyclone
2. Control Device or Method Code(s): 76

Emissions Unit Details

1. Package Unit: Manufacturer: Westinghouse	Model Number: 13-A-1685-1
2. Generator Nameplate Rating: 17 MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

Emissions Unit Control Equipment – (37.5 MW Boiler Unit #7)

1. Control Equipment/Method Description (Limit to 200 characters per device or method): Multiple Cyclone for particulate matter control.
2. Control Device or Method Code(s): 76

Emissions Unit Details

1. Package Unit: Manufacturer: Brown Boveri	Model Number: Type DSQ2g44
2. Generator Nameplate Rating: 33MW	
3. Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

<u>Emissions Unit Control Equipment</u> – (56.1 MW Boiler Unit #8)

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

<u>Emissions Unit Details</u>

1. Package Unit: Manufacturer: Delaval	Model Number: N/A
2. Generator Nameplate Rating: 56 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 – (2.75 MW West Diesel #1)

1. Maximum Heat Input Rate: 29 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:		
	24 hours/day	7 days/week
	52 weeks/year	8760 hours/year

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

Unit 001 is currently limited to 28.9 MMBtu/hr maximum heat input.

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

Emissions Unit Operating Capacity and Schedule – (2.75 MW East Diesel #2)

1. Maximum Heat Input Rate: 29 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:	24 hours/day 52 weeks/year	7 days/week 8760 hours/year
1. Operating Capacity/Schedule Comment (limit to 200 characters): Unit 002 is currently limited to 28.9 MMBtu/hr maximum heat input.		

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

Emissions Unit Operating Capacity and Schedule – (31.6 MW Combined Cycle Gas Turbine Unit #9)

1. Maximum Heat Input Rate: 415 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:		
	24 hours/day	7 days/week
	52 weeks/year	8760 hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):		

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

<u>Emissions Unit Operating Capacity and Schedule</u> – (16.5 MW Boiler Unit #6)

1. Maximum Heat Input Rate: 219 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:	24 hours/day 52 weeks/year	7 days/week 8760 hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):		

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

Emissions Unit Operating Capacity and Schedule – **(37.5 MW Boiler Unit #7)**

1. Maximum Heat Input Rate: 470 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:		
	24 hours/day	7 days/week
	52 weeks/year	8760 hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):		

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

Emissions Unit Operating Capacity and Schedule – (56.1 MW Boiler Unit #8)

1. Maximum Heat Input Rate: 644 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:		
	24 hours/day	7 days/week
	52 weeks/year	8760 hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters):		

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations – (2.75 MW West Diesel #1)

Unregulated Emission Unit

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations – (2.75 MW East Diesel #2)

Unregulated Emission Unit

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations – (31.6 MW Combined Cycle Gas Turbine Unit #9)

40CFR60.7 – Notification and Recordkeeping (NSPS)	40CFR60.8 – Performance Tests (NSPS)
40CFR60.11 – Compliance with Standards and Maintenance Requirements (NSPS)	40CFR60.12 – Circumvention (NSPS)
40CFR60.13 – Monitoring Requirements (NSPS)	40CFR60.19 – General Notification and Reporting
40CFR60 – Subpart GG – Standards of Performance for Stationary Gas Turbines (NSPS)	40CFR70 – State Operating Permits
62-4.001 through 62-4.160, FAC – Permits Part I General	62-4.210, FAC – Construction Permits
62-4.220, FAC – Operating Permits	62-103.150, FAC – Public Notice of Application and Proposed Agency Action
62-210, FAC – Stationary Sources	62-212.300, FAC Sources not Subject to PSD or Nonattainment Requirements
62-213, FAC – Operation Permits for Major Sources of Air Pollution (Title V)	62-272.300, FAC – Ambient Air Quality Standards
62-273, FAC – Air Pollution Episodes	62-296.310(2)(a), FAC – General Visible Emission Standards
62-296.310(3), FAC – Unconfined Emissions of Particulate Matter	62-296.320(2), FAC – General Pollutant Emissions Limiting Standards, Objectionable Odors
62-296.330, FAC – Best Available Control Technology	62-296.800, FAC – New Source Performance Standards
62-297.310 through 62-297.400, FAC – Compliance Test Requirements	62-297.570, FAC – Compliance Test Reports

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations – (16.5 MW Boiler Unit #6)

40CFR70 – State Operating Permits	62-103.150, FAC – Public Notice of Application and Proposed Agency Action
62-210, FAC – Stationary Sources; except 62-210.550	62-213, FAC – Operation Permits for Major Sources of Air Pollution (Title V)
62-272.300, FAC – Ambient Air Quality Standards	62-273, FAC – Air Pollution Episodes
62-296.310(2)(a), FAC – General Visible Emission Standards	62-296.310(3), FAC – Unconfined Emissions of Particulate Matter
62-296.320(2), FAC – General Pollutant Emissions Limiting Standards, Objectionable Odors	62-297.310 through 62-297.400, FAC – Compliance Test Requirements
62-297.570, FAC – Compliance Test Reports	

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations – 37.5 MW Boiler Unit #7)

40CFR70 – State Operating Permits	40CFR72 – Regulations on Permits
40CFR73 – SO_2 Allowance System	40CFR75 – Regulations for CEMs under Acid Rain Requirements
40CFR77 – Excess Emissions for Acid Rain Units	40CFR78 – Appeal Procedures for Acid Rain Units
62-103.150, FAC – Public Notice of Application and Proposed Agency Action	62-210, FAC – Stationary Sources; except 62-210.550
62-213, FAC – Operation Permits for Major Sources of Air Pollution (Title V)	62-272.300, FAC – Ambient Air Quality Standards
62-273, FAC – Air Pollution Episodes	62-296.310(2)(a), FAC – General Visible Emission Standards
62-296.310(3), FAC – Unconfined Emissions of Particulate Matter	62-296.320(2), FAC – General Pollutant Emissions Limiting Standards, Objectionable Odors
62-296.405(1), FAC – Spec. Emissions Limiting & Performance Standards for Existg Foss Fuel Fire Steam Gen. >250 MMBtu/hr	62-297.310 through 62-297.400, FAC – Compliance Test Requirements
62-297.570, FAC – Compliance Test Reports	

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations – (56.1 MW Boiler Unit #8)

40CFR60.7 – Notification and Recordkeeping (NSPS)	40CFR60.8 – Performance Tests (NSPS)
40CFR60.11 – Compliance with Standards and Maintenance Requirements (NSPS)	40CFR60.12 – Circumvention (NSPS)
40CFR60.13 – Monitoring Requirements (NSPS)	40CFR60 – Subpart D – Standards of Performance for Fossil-Fuel-Fired Steam Generators (NSPS)
40CFR70 – State Operating Permits	40CFR72 – Regulations on Permits
40CFR73 – SO_2 Allowance System	40CFR75 – Regulations for CEMs under Acid Rain Requirements
40CFR77 – Excess Emissions for Acid Rain Units	40CFR78 – Appeal Procedures for Acid Rain Units
40CFR60.19 – General Notification and Reporting Requirements	62-4.001 through 62-4.160, FAC – Permits Part I General
62-4.210, FAC – Construction Permits	62-4.220, FAC - Operating Permits
62-103.150, FAC – Public Notice of Application and Proposed Agency Action	62-210, FAC – Stationary Sources
62-212.300, FAC – Sources not Subject to PSD or Nonattainment Requirements	62-213, FAC – Operation Permits for Major Sources of Air Pollution (Title V)
62-272.300, FAC – Ambient Air Quality Standards	62-273, FAC – Air Pollution Episodes
62-296.310(2)(a), FAC – General Visible Emission Standards	62-296.310(3), FAC – Unconfined Emissions of Particulate Matter
62-296.320(2), FAC – General Pollutant Emissions Limiting Standards, Objectionable Odors	62-296.405(1), FAC – Spec. Emissions Limiting & Performance Standards for Existg Foss Fuel Fire Steam Gen. >250 MMBtu/hr
62-296.800, FAC – New Source Performance Standards	62-297.310 through 62-297.400, FAC – Compliance Test Requirements
62-297.500(1), FAC – Continuous Emissions Monitoring Requirements	62-297.570, FAC – Compliance Test Reports

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

Emission Point Description and Type– (2.75 MW West Diesel #1)

1. Identification of Point on Plot Plan or Flow Diagram? No. 1 Diesel	1. 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: 23 feet	7. Exit Diameter: 3.0 feet
8. Exit Temperature: 950 °F	9. Actual Volumetric Flow Rate: 16595 acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates: Zone: East (km): North (km):		
14. Emission Point Comment (limit to 200 characters):		

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

Emission Point Description and Type– (2.75 MW East Diesel #2)

1. Identification of Point on Plot Plan or Flow Diagram? No. 2 Diesel	1. 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:	

1. Discharge Type Code: V	6. Stack Height: 23 feet	7. Exit Diameter: 3.0 feet
8. Exit Temperature: 950 °F	9. Actual Volumetric Flow Rate: 16595 acfm	10. Water Vapor: %
11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet	
13. Emission Point UTM Coordinates: Zone:	East (km):	North (km):
14. Emission Point Comment (limit to 200 characters):		

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

Emission Point Description and Type– (31.6 MW Combined Cycle Gas Turbine Unit #9)

1. Identification of Point on Plot Plan or Flow Diagram? No. 9 GT	1. 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:

1. Discharge Type Code: V	6. Stack Height: 68 feet	7. Exit Diameter: 11.2 feet
8. Exit Temperature: 426 °F	9. Actual Volumetric Flow Rate: 353500 acfm	10. Water Vapor: 9.07 %

11. Maximum Dry Standard Flow Rate: 221585 dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: East (km): North (km):

14. Emission Point Comment (limit to 200 characters):

The combustion turbine stack has a rectangular exit with dimensions 10.6 ft by 9.25 ft. The equivalent diameter for a stack with a circular exit is 11.2 ft. The combustion turbine exhausts through a heat recovery steam generator.

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

Emission Point Description and Type– (16.5 MW Boiler Unit #6)

1. Identification of Point on Plot Plan or Flow Diagram? No. 6 Boiler	1. 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:	

1. Discharge Type Code: V	6. Stack Height: 148 feet	7. Exit Diameter: 5.0 feet
8. Exit Temperature: 325 °F	9. Actual Volumetric Flow Rate: 42735 acfm	10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):	
14. Emission Point Comment (limit to 200 characters):	

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

Emission Point Description and Type– (37.5 MW Boiler Unit #7)

1. Identification of Point on Plot Plan or Flow Diagram? No. 7 Boiler	1. 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:

1. Discharge Type Code: V	6. Stack Height: 147 feet	7. Exit Diameter: 7.1 feet
8. Exit Temperature: 308 °F	9. Actual Volumetric Flow Rate: 145081 acfm	10. Water Vapor: 13.73 %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: East (km): North (km):

14. Emission Point Comment (limit to 200 characters):

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

Emission Point Description and Type– (56.1 MW Boiler Unit #8)

1. Identification of Point on Plot Plan or Flow Diagram? No. 8 Boiler	1. 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:	

1. Discharge Type Code: V	6. Stack Height: 150 feet	7. Exit Diameter: 8.0 feet
8. Exit Temperature: 334 °F	9. Actual Volumetric Flow Rate: 252011 acfm	10. Water Vapor: 15.66 %

11. Maximum Dry Standard Flow Rate: dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: East (km): North (km):	
14. Emission Point Comment (limit to 200 characters):	

E. SEGMENT (PROCESS/FUEL) INFORMATION
(2.75 MW West Diesel #1)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): No. 2 Distillate Fuel Oil Burned in Diesel Engine		
1. Source Classification Code (SCC): 2-02-004-01	3. SCC Units: Thousand Gallons Burned (all liquid fuels)	
1. Maximum Hourly Rate: 0.210	1. Maximum Annual Rate: 1826	6. Estimated Annual Activity Factor:
1. Maximum % Sulfur: 0.50	2. Maximum % Ash:	1. Million Btu per SCC Unit: 139
10. Segment Comment (limit to 200 characters):		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(2.75 MW East Diesel #2)

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): No. 2 Distillate Fuel Oil Burned in Diesel Engine		
1. Source Classification Code (SCC): 2-02-004-01	3. SCC Units: Thousand Gallons Burned (all liquid fuels)	
1. Maximum Hourly Rate: 0.210	1. Maximum Annual Rate: 1826	6. Estimated Annual Activity Factor:
1. Maximum % Sulfur: 0.50	2. Maximum % Ash:	1. Million Btu per SCC Unit: 139
10. Segment Comment (limit to 200 characters):		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(31.6 MW Combined Cycle Gas Turbine Unit #9)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

Natural gas burned as primary fuel in gas turbine (emissions related to million cubic feet burned); No. 2 distillate fuel oil burned as backup fuel in gas turbine (emissions related to 1000 gallons of fuel burned).

1. Source Classification Code (SCC): 2-01-002-01	1. SCC Units: Million Cubic Feet Burned (all gaseous fuels)	
1. Maximum Hourly Rate: 0.403	2. Maximum Annual Rate: 3521	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	1. Million Btu per SCC Unit: 1031

10. Segment Comment (limit to 200 characters):

The sulfur content of natural gas is nil. The hours of operation for the unit is limited by the existing air permit to 8736 hours per year.

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters):

No. 2 distillate fuel oil used only as backup fuel burned in gas turbine (emissions related to 1000 gallons burned); natural gas is primary fuel burned.

1. Source Classification Code (SCC): 2-01-001-01	3. SCC Units: Thousand Gallons Burned (all liquid fuels)	
1. Maximum Hourly Rate: 2.988	1. Maximum Annual Rate: 26109	6. Estimated Annual Activity Factor:
1. Maximum % Sulfur: 0.50	8. Maximum % Ash:	1. Million Btu per SCC Unit: 139

1. Segment Comment (limit to 200 characters):

The sulfur content of fuel burned in the combustion turbine is limited by the current permit to 0.5% sulfur by weight.

E. SEGMENT (PROCESS/FUEL) INFORMATION
(16.5 MW Boiler Unit #6)

Segment Description and Rate: Segment __1__ of __2__

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Boiler burns natural gas as primary fuel (emissions related to million cubic feet of natural gas burned). Residual fuel oil No. 6 may be burned as an emergency backup fuel (emissions related to 1,000 gallons burned).		
1. Source Classification Code (SCC): 1-01-006-01	1. SCC Units: Million Cubic Feet Burned (all gaseous fuels)	
1. Maximum Hourly Rate: 0.211	2. Maximum Annual Rate: 1860	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	Million Btu per SCC Unit: 1031
10. Segment Comment (limit to 200 characters): The sulfur content of natural gas is nil. The annual heat input for Units 6, 7, and 8 is limited to 4,534,930 MM Btu/yr by the current air permit.		

Segment Description and Rate: Segment __2__ of __2__

1. Segment Description (Process/Fuel Type) (limit to 500 characters): No. 6 residual fuel oil burned as secondary fuel (emission related to 1,000 gallons burned). No. 6 fuel oil consumption is limited to a total of 400 hours per year for Units 6, 7, and 8 by the current air permit.		
1. Source Classification Code (SCC): 1-01-004-01	3. SCC Units: Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate: 1.480	5. Maximum Annual Rate: 592	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.72	8. Maximum % Ash:	9. Million Btu per SCC Unit: 148
10. Segment Comment (limit to 200 characters): No. 6 fuel consumption is currently limited by existing air permit to a total of 400 hours per year for Units 6, 7, and 8. The sulfur content of the fuel is limited to 0.8 lbs/MMBtu.		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(37.5 MW Boiler Unit #7)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Boiler burns natural gas as primary fuel (emissions related to million cubic feet of burned); No. 6 residual fuel oil may be burned as secondary, emergency fuel (emissions related to 1,000 gallons burned).		
1. Source Classification Code (SCC): 1-01-006-01	3. SCC Units: Thousand Gallons Burned (all liquid fuels)	
1. Maximum Hourly Rate: 0.456	1. Maximum Annual Rate: 3993	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	Million Btu per SCC Unit: 1031
10. Segment Comment (limit to 200 characters): The sulfur content of natural gas is nil. The annual heat input for Units 6,7, and 8 is limited to 4,534,930 MM Btu/yr by the current air permit.		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): No. 6 residual fuel oil burned as secondary/emergency fuel (emission related to 1,000 gallons burned); natural gas is burned as the primary fuel.		
1. Source Classification Code (SCC): 1-01-004-01	3. SCC Units: Thousand Gallons Burned (all liquid fuels)	
1. Maximum Hourly Rate: 3.176	1. Maximum Annual Rate: 1270	6. Estimated Annual Activity Factor:
1. Maximum % Sulfur: 0.72	8. Maximum % Ash:	1. Million Btu per SCC Unit: 148
1. Segment Comment (limit to 200 characters): Combustion of No. 6 residual fuel oil is limited by the current air permit to a combined total of 400 hours for Units 6, 7, and 8.		

E. SEGMENT (PROCESS/FUEL) INFORMATION
(56.1 MW Boiler Unit #8)

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Natural gas is burned as primary fuel (emission related to million cubic feet burned); No. 6 fuel may be burned as secondary/emergency fuel (emissions related to thousand gallons burned).		
1. Source Classification Code (SCC): 1-01-006-01	1. SCC Units: Million Cubic Feet Burned (all gaseous fuels)	
1. Maximum Hourly Rate: 0.592	2. Maximum Annual Rate: 4399	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	Million Btu per SCC Unit: 1031
10. Segment Comment (limit to 200 characters): The sulfur content of natural gas is nil. The total combined heat input for Units 6, 7, and 8 is limited to 4,534,930 MM Btu/yr by the current air permit.		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): No. 6 residual fuel oil may be burned as secondary/emergency fuel (emission related to 1,000 gallons burned); natural gas is burned as the primary fuel.		
1. Source Classification Code (SCC): 1-01-004-01	3. SCC Units: Thousand Gallons Burned (all liquid fuels)	
1. Maximum Hourly Rate: 4.128	1. Maximum Annual Rate: 1651	6. Estimated Annual Activity Factor:
1. Maximum % Sulfur: 0.72	8. Maximum % Ash:	1. Million Btu per SCC Unit: 148
1. Segment Comment (limit to 200 characters): The current air permit limits the total No. 6 fuel oil consumption to less than or equal to 400 hours per year for Units 6, 7, and 8. The sulfur content of the fuel is limited to 0.8 lbs/MMBtu.		

F. EMISSIONS UNIT POLLUTANTS
(2.75 MW West Diesel #1)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			
NOx			
PM			
PM10			
SO_2			
VOC			

F. EMISSIONS UNIT POLLUTANTS
(2.75 MW East Diesel #2)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			
NOx			
PM			
PM10			
SO_2			
VOC			

F. EMISSIONS UNIT POLLUTANTS
(31.6 MW Combined Cycle Gas Turbine Unit #9)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			
NOx	028		
PM			
PM10			
SO_2			
VOC			

F. EMISSIONS UNIT POLLUTANTS
(16.5 Boiler Unit #6)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			
NOx			
PM	076		
PM10	076		
SO_2			
VOC			

F. EMISSIONS UNIT POLLUTANTS
(37.5 MW Boiler Unit #7)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			
NOx			
PM	076		
PM10	076		
SO_2			
VOC			

F. EMISSIONS UNIT POLLUTANTS
(56.1 MW Boiler Unit #8)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
CO			
NOx			
PM			
PM10			
SO_2			
VOC			

Emissions Unit Information Section 1 **of** 6

Pollutant Detail Information Page 1 **of** 6

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

Potential/Fugitive Emissions – **(2.75 MW West Diesel #1)**

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 23.4100 lb/hour 102.5300 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.81000 lbs/MMBtu Reference: AP-42	7. Emissions Method Code: 3
8. Calculation of Emissions (limit to 600 characters): 0.81 lb/MMBtu x 28.90 MMBtu/hr = 23.41 lbs/hr 23.41 lbs/hr x ton/2,000 lbs x 8,760 hr/yr = 102.53 tons/yr	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Unregulated emission unit.	

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

Potential/Fugitive Emissions – (2.75 MW West Diesel #1)

1. Pollutant Emitted: NOx	2. Total Percent Efficiency of Control:
3. Potential Emissions: 89.5900 lb/hour 392.4000 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 3.10000 lbs/MMBtu Reference: AP-42	7. Emissions Method Code: 3

8. Calculation of Emissions (limit to 600 characters):

3.1 lb/MMBtu x 28.90 MMBtu/hr = 89.59 lbs/hr
89.59 lbs/hr x ton/2,000 lbs x 8,760 hr/yr = 392.40 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Unregulated emission unit.

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

Potential/Fugitive Emissions – (2.75 MW West Diesel #1)

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 10.4200 lb/hour 45.6600 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 50.00000 lb/1000 gal Reference: AIRS	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): 50 lb/1000 gal x 1000 gal/138.62 MMBtu x 28.90 MMBtu/hr = 10.42 lb/hr 10.42 lb/hr x ton/2,000 lb x 8,760 hr/yr = 45.66 tons/yr	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Unregulated emission unit.	

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

Potential/Fugitive Emissions – (2.75 MW West Diesel #1)

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 9.5900 lb/hour 42.0100 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 46.00000 lb/1000 gal Reference: AIRS	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): 46 lb/1000 gal x 1000 gal/138.62 MMBtu x 28.90 MMBtu/hr = 9.59 lb/hr 9.59 lb/hr x ton/2,000 lb x 8,760 hr/yr = 42.01 tons/yr	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Unregulated emission unit.	

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

Potential/Fugitive Emissions – (2.75 MW West Diesel #1)

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 15.0100 lb/hour 65.7500 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.51940 lb/MMBtu Reference: Mass Balance	7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): 1,000 gal/138.62 MMBtu x 7.2 lb/gal x 0.5%S x 2 = 0.5194 lb/MMBtu 0.5194 lb/MMBtu x 28.90 MMBtu/hr = 15.01 lb/hr 150.1 lb/hr x ton/2,000 lb x 8,760 hr/yr = 65.75 tons/yr	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Unregulated emission unit.	

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

Potential/Fugitive Emissions – (2.75 MW West Diesel #1)

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 2.8900 lb/hour 12.6600 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.10000 lb/MMBtu Reference: AP-42	7. Emissions Method Code: 3
8. Calculation of Emissions (limit to 600 characters): 0.10 lbs/MMBtu x 28.90 MMBtu/hr = 2.89 lbs/hr 2.89 lb/hr x ton/2,000 lb x 8,760 hr/yr = 12.66 tons/yr	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Unregulated emission unit.	

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

Potential/Fugitive Emissions – **(2.75 MW East Diesel #2)**

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:	
3. Potential Emissions: 23.4100 lb/hour 102.5300 tons/year		4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: 0.81000 lbs/MMBtu Reference: AP-42		7. Emissions Method Code: 3
8. Calculation of Emissions (limit to 600 characters): 0.81 lb/MMBtu x 28.90 MMBtu/hr = 23.41 lb/hr 23.41 lb/hr x ton/2,000 lbs x 8,760 hr/yr = 102.53 tons/yr		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Unregulated emission unit.		

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

Potential/Fugitive Emissions – (2.75 MW East Diesel #2)

1. Pollutant Emitted: NOx	2. Total Percent Efficiency of Control:
3. Potential Emissions: 89.5900 lb/hour 392.4000 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 3.10000 lb/MMBtu Reference: AP-42	7. Emissions Method Code: 3
8. Calculation of Emissions (limit to 600 characters): 3.1 lb/MMBtu x 28.90 MMBtu/hr = 89.59 lb/hr 89.59 lb/hr x ton/2,000 lbs x 8,760 hr/yr = 392.40 tons/yr	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Unregulated emission unit.	

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

Potential/Fugitive Emissions – **(2.75 MW East Diesel #2)**

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 10.4200 lb/hour 45.6600 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 50.00000 lbs/1000 gal Reference: AIRS	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): 50 lb/1000 gal x 1000 gal/138.62 MMBtu x 0.3607 lb/MMBtu = 10.42 lb/hr 0.3607 lb/MMBtu x 28.90 MMBtu/hr = 10.42 lb/hr 10.42 lb/hr x ton/2,000 lb x 8,760 hr/yr = 45.66 tons/yr	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Unregulated emission unit.	

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

<u>Potential/Fugitive Emissions</u> – (2.75 MW East Diesel #2)

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
1. Potential Emissions: 9.5900 lb/hour 42.0100 tons/yr	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 46.00000 lb/1000 gal Reference: AIRS	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): 46 lb/1000 gal x 1000 gal/138.62 MMBtu = 0.3319 lb/MMBtu 0.3319 lb/MMBtu x 28.90 MMBtu/hr = 9.59 lb/hr 9.59 lb/hr x ton/2,000 lb x 8760 hr/yr = 42.01 tons/yr	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Unregulated emission unit.	

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

<u>Potential/Fugitive Emissions</u> – (2.75 MW East Diesel #2)

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:	
3. Potential Emissions: 15.0100 lb/hour 65.7500 tons/year		4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: 0.51940 lb/MMBtu Reference: Mass Balance		7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): 1,000 gal/138.62 MMBtu x 7.2 lb/gal x 0.5%S x 2 = 0.5194 lb/MMBtu 0.5194 lb/MMBtu x 28.90 MMBtu/hr = 15.01 lb/hr 15.01 lb/hr x ton/2,000 lb x 8,760 hr/yr = 65.75 tons/yr		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Unregulated emission unit.		

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

Potential/Fugitive Emissions – (2.75 MW East Diesel #2)

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 2.8900 lb/hour 12.6600 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.10000 lb/MMBtu Reference: AP-42	7. Emissions Method Code: 3

8. Calculation of Emissions (limit to 600 characters):

0.10 lb/MMBtu x 28.90 MMBtu/hr = 2.89 lb/hr
2.89 lb/hr x ton/2,000 lb x 8,760 hr/yr = 12.66 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Unregulated emission unit.

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

Potential/Fugitive Emissions – **(31.6 MW Combined Cycle Gas Turbine Unit #9)**

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 32.8500 lb/hour 110.4000 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.07910 lb/MMBtu Reference: Permit Limit	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): 32.85 lb/hr (existing air permit limit) 110.4 tons/yr (existing air permit limit)	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Potential emissions of CO are currently limited in the existing air permit to 32.85 lbs/hr and 110.4 tons/yr.	

Allowable Emissions Allowable Emissions __1__ of __1__

1. Basis for Allowable Emissions Code: OTHER	1. Future Effective Date of Allowable Emissions:
1. Requested Allowable Emissions and Units: 32.85000 lb/hr	2. Equivalent Allowable Emissions: 32.85000 lb/hour 110.4000 tons/year
1. Method of Compliance (limit to 60 characters): Annual testing is in accordance with EPA Method 10, conducted while the unit is operating within 10% of its rated capacity.	
1. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters): Allowable emissions request based on current permit limits. No. 2 fuel oil may be burned as an emergency back-up fuel.	

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

Potential/Fugitive Emissions – **(31.6 MW Combined Cycle Gas Turbine Unit #9)**

1. Pollutant Emitted: NOx	2. Total Percent Efficiency of Control: 53.2%
3. Potential Emissions: 135.6900 lb/hour 594.32 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.69800 lb/MMBtu Reference: AP-42	7. Emissions Method Code: 3
8. Calculation of Emissions (limit to 600 characters): 0.69800 lb/MMBtu x 415.3 MMBtu/hr x (100%-53.2%) = 135.6900 lb/hr 135.6900 lb/hr x ton/2,000 lb x 8,760 hr/yr = 594.32 tons/yr	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Potential emissions are based on an existing air permit stack gas limitation of 84 ppm NOx. Maximum NOx emissions occur with the combustion of No. 2 Fuel Oil.	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 84.00000 ppm	4. Equivalent Allowable Emissions: 135.6900 lb/hour 594.32 tons/year
5. Method of Compliance (limit to 60 characters): Annual testing in accordance with EPA Method 20, conducted while the unit is operating within 10% of its rated capacity. 40CFR60 Subpart GG- NSPS Monitoring requirements will be met, including: 1) a continuous monitoring system will monitor and record the fuel consumption and ratio of water to fuel being fired in the turbine; and 2) the nitrogen content of the fuel fired will be monitored.	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Allowable emissions request based on current permit limit and 40CFR60.332. This allowable emissions limit is only applicable during fuel oil firing. No. 2 fuel oil may be burned as an emergency back-up fuel.	

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

Potential/Fugitive Emissions – (31.6 MW Combined Cycle Gas Turbine Unit #9)

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 25.3300 lb/hour 110.95 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.06099 lb/MMBtu Reference: AP-42	7. Emissions Method Code: 3

8. Calculation of Emissions (limit to 600 characters):

0.061 lb/MMBtu x 415.300 MMBtu/hr = 25.330 lb/hr
25.33 lb/hr x ton/2,000 lbs x 8,760 hr/yr = 110.95 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Maximum PM emissions occur during combustion of No. 2 fuel oil, (emergency back-up fuel). Emissions limited only by 15% opacity limit.

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

Potential/Fugitive Emissions – (31.6 MW Combined Cycle Gas Turbine Unit #9)

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 25.3300 lb/hour 110.95 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.06099 lb/MMBtu Reference: AP-42	7. Emissions Method Code: 3
8. Calculation of Emissions (limit to 600 characters): 0.061 lb/MMBtu x 415.300 MMBtu/hr = 25.330 lb/hr 25.33 lb/hr x ton/2,000 lb x 8,760 hr/yr = 110.95 tons/yr	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): All PM emissions assumed as PM-10 emissions. Maximum PM-10 emissions occur during combustion of No. 2 fuel oil, (emergency back-up fuel). Emissions limited only by 15% opacity limit.	

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

Potential/Fugitive Emissions – **(31.6 MW Combined Cycle Gas Turbine Unit #9)**

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 319.5100 lb/hour 1399.45 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.76929 lb/MMBtu Reference: Permit Limit	7. Emissions Method Code: 5

8. Calculation of Emissions (limit to 600 characters):

Current limit is 150 ppmvd @ 15% O_2
150 cu. ft. SO_2/1,000,000 cu. ft. gas x 8,710 cu. ft. gas/MMBtu x (20.9/(20.9-15.0)) x 415.3 MM Btu/hr x 64 lb/385 cu. ft. = 319.51 lb/hr ;
319.51 lb/hr x ton/2000 lbs. X 8,760 hrs/yr = 1399.45 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Potential SO_2 emissions are based on the current permit limitation of 0.015% SO_2 by volume at 15% oxygen on a dry basis.

Allowable Emissions Allowable Emissions __1__ of __1__

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
1. Requested Allowable Emissions and Units: 150.00000 ppmvd @15% O_2	4. Equivalent Allowable Emissions: 319.5100 lb/hr 1399.45 tons/year

1. Method of Compliance (limit to 60 characters):
Annual testing in accordance with EPA method 20 or ASTM 1552, conducted while the unit is operating within 10% of its rated capacity. Additionally, 40CFR60 Subpart GG-NSPS Monitoring Requirements will be met, including monitoring the sulfur content of the fuel fired in the turbine.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions request based on current permit limit and 40CFR60.333. No. 2 fuel oil with a maximum sulfur content of 0.5% by weight may be burned as an emergency back-up fuel.

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

Potential/Fugitive Emissions – **(31.6 MW Combined Cycle Gas Turbine Unit #9)**

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 9.9700 lb/hour 43.6700 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.02400 lb/MMBtu Reference: AP-42	7. Emissions Method Code: 3
8. Calculation of Emissions (limit to 600 characters): 0.024 lb/MMBtu x 415.300 MMBtu/hr = 9.970 lb/hr 9.97 lb/hr x ton/2,000 lb x 8,760 hr/yr = 43.67 tons/yr	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Maximum potential VOC emissions occur during combustion of natural gas. VOC emissions not limited in current permit.	

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

Potential/Fugitive Emissions – (16.5 MW Boiler Unit #6)

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 7.93 lb/hour 4.33 tons/year	4. Synthetically Limited? [Y]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 40.00000 lb/MMCF Reference: AP-42	7. Emissions Method Code: 3

8. Calculation of Emissions (limit to 600 characters):

Natural Gas
0.66 lb/hr x 8,360 hr/yr x 1 ton/2,000 lb = 2.76 tons/yr
Fuel Oil
7.93 lb/hr x 400 hr/yr x 1 ton/2,000 lb = 1.57 tons/yr

Potential – 2.76 tons/yr + 1.57 tons/yr = 4.33 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Potential CO emissions are based on natural gas combustion.

Allowable Emissions Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.15 lb/hr	4. Equivalent Allowable Emissions: 0.15 lb/hour 0.66 tons/year

5. Method of Compliance (limit to 60 characters):
Annual testing in accordance with EPA Method 10, conducted while the unit is operating Within 10 % of its rated capacity.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions request based on current permit allowable (OGC Case No. 91-1610). This allowable emissions limit is only applicable during natural gas firing. Emissions are not limited during No. 2 fuel oil firing (Units 6, 7, and 8 may burn No. 2 fuel oil for up to a combined total of 400 hours per year).

<u>Allowable Emissions</u> Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 7.93 lb/hr	4. Equivalent Allowable Emissions: 7.93 lb/hour 1.57 tons/year

5. Method of Compliance (limit to 60 characters):
Annual testing in accordance with EPA Method 10, conducted while is operating within 10% of its rated capacity, to be required only if the Unit burns fuel oil for more than 400 hours in a calendar year.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Limit of 400 hr/yr fuel oil combustion for Units 6, 7, and 8 combined. Emissions are not limited when firing oil.

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

Potential/Fugitive Emissions – (16.5 MW Boiler Unit #6)

1. Pollutant Emitted: NOx	2. Total Percent Efficiency of Control:
3. Potential Emissions: 38.07 lb/hour 13.09 tons/year	4. Synthetically Limited? [Y]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 550.00000 lb/MMCF Reference: AP-42	7. Emissions Method Code: 3
8. Calculation of Emissions (limit to 600 characters): Natural Gas 1.31 lb/hr x 8,360 hr/yr x 1 ton/2,000 lb = 5.48 tons/yr Fuel Oil 38.07 lb/hr x 400 hr/yr x 1 ton/2,000 lb = 7.61 tons/yr Potential – 5.48 tons/yr + 7.61 tons/yr = 13.09 tons/yr	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Potential NOx emissions are based on natural gas combustion for the entire year.	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 1.31 lb/hr	4. Equivalent Allowable Emissions: 1.31 lb/hour 5.74 tons/year
5. Method of Compliance (limit to 60 characters): Annual testing in accordance with EPA Method 7, 7E, conducted while the unit is operating within 10% of its rated capacity.	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Allowable emissions request based on current permit allowable (OGC Case No. 91-1610). This allowable emissions limit is only applicable during natural gas firing. Emissions are not limited during No. 2 fuel oil firing (Units 6, 7, and 8 may burn No. 2 fuel oil for up to a combined total of 400 hours per year).	

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 38.07 lb/hr	4. Equivalent Allowable Emissions: 38.07 lb/hour 7.61 tons/year
5. Method of Compliance (limit to 60 characters): Annual testing in accordance with EPA Method 7E, conducted while is operating within 10% of its rated capacity, to be required only if the Unit burns fuel oil for more than 400 hours in a calendar year.	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Limit of 400 hr/yr fuel oil combustion for Units 6, 7, and 8 combined. Emissions are not limited when firing oil.	

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

Potential/Fugitive Emissions – (16.5 MW Boiler Unit #6)

1. Pollutant Emitted: PM

2. Total Percent Efficiency of Control:

3. Potential Emissions: 21.8900 lb/hour 6.05 tons/year

4. Synthetically Limited? [Y]

5. Range of Estimated Fugitive Emissions:
[ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year

6. Emission Factor: 0.10000 lb/MMBtu
Reference: Air Permit- #7, 8

7. Emissions Method Code: 5

8. Calculation of Emissions (limit to 600 characters):
Natural Gas
0.4 lb/hr x ton/2,000 lb x 8,360 hr/yr = 1.67 tons/yr
Fuel Oil
0.1 lb/MMBtu x 218.9 MMBtu/hr = 21.89 lb/hr
21.89 lb/hr x 400 hr/yr x ton/2,000 lb = 4.38 tons/yr

Potential- 1.67 tons/yr + 4.38 tons/yr = 6.05 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Potential PM emissions are based on 400 hr/yr fuel oil combustion and natural gas combustion for the remainder of the year. Units 6, 7, and 8 are limited to a combined total of 400 hr/yr on No. 2 fuel oil.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units: 0.40000 lb/hr

4. Equivalent Allowable Emissions: 0.40000 lb/hour 1.7500 tons/year

5. Method of Compliance (limit to 60 characters):
Annual testing in accordance with EPA Method 5, conducted while the unit is operating within 10% of its rated capacity, except that particulate matter tests…

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions request based on the unit's current permit limit. This allowable emissions limit is only applicable during natural gas firing. Units 6, 7, and 8 may burn No. 2 fuel oil for up to a combined total of 400 hours per year.

Allowable Emissions Allowable Emissions 2 of 2

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: 21.8900 lb/hour 4.3800 tons/year
5. Method of Compliance (limit to 60 characters): Annual testing in accordance with EPA Method 5, conducted while is operating within 10% of its rated capacity, to be required only if the Unit burns fuel oil for more than 400 hours in a calendar year.	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): No. 2 fuel oil may be burned as an emergency back-up fuel for a combined total of 400 hr/yr on Units 6, 7, and 8.	

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

Potential/Fugitive Emissions – (16.5 MW Boiler Unit #6)

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 21.8900 lb/hour 6.05 tons/year	4. Synthetically Limited? [Y]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.10000 lb/MMBtu Reference: Air Permit- #7, 8	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): Natural Gas 0.4 lb/hr x ton/2,000 lb x 8,360 hr/yr = 1.67 tons/yr Fuel Oil 0.1 lb/MMBtu x 218.9 MMBtu/hr = 21.89 lb/hr 21.89 lb/hr x 400 hr/yr x ton/2,000 lb = 4.38 tons/yr Potential- 1.67 tons/yr + 4.38 tons/yr = 6.05 tons/yr	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Potential PM emissions are based on 400 hr/yr fuel oil combustion and natural gas combustion for the remainder of the year. Units 6, 7, and 8 are limited to a combined total of 400 hr/yr on No. 2 fuel oil.	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.40000 lb/hr	4. Equivalent Allowable Emissions: 0.40000 lb/hour 1.7500 tons/year
5. Method of Compliance (limit to 60 characters): Annual testing in accordance with EPA Method 5, conducted while the unit is operating within 10% of its rated capacity, except that particulate matter tests…	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Allowable emissions request based on the unit's current permit limit. This allowable emissions limit is only applicable during natural gas firing. Units 6, 7, and 8 may burn No. 2 fuel oil for up to a combined total of 400 hours per year.	

Allowable Emissions Allowable Emissions 2 of 2

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: 21.8900 lb/hour 4.3800 tons/year

5. Method of Compliance (limit to 60 characters):
Annual testing in accordance with EPA Method 5, conducted while is operating within 10% of its rated capacity, to be required only if the Unit burns fuel oil for more than 400 hours in a calendar year.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

No. 2 fuel oil may be burned as an emergency back-up fuel for a combined total of 400 hr/yr on Units 6, 7, and 8.

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

<u>Potential/Fugitive Emissions</u> – (16.5 MW Boiler Unit #6)

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 175.1200 lb/hour 45.4700	4. Synthetically Limited? [Y]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.80000 lb/MMBtu Reference: Air Permit Limit	7. Emissions Method Code: 5

8. Calculation of Emissions (limit to 600 characters):
<u>Natural Gas</u>
2.500 lb/hr x ton/2,000 lb x 8,360 hr/yr = 10.95 tons/yr
<u>Fuel Oil</u>
0.80 lb/MMBtu x 218.9 MMBtu/hr = 175.12 lb/hr (No. @ Fuel Oil)
175.12 lb/hr x ton/2,000 lb x 400 hr/yr = 35.02 tons/yr

<u>Potential</u>- 10.95 tons/yr + 35.02 tons/yr = 45.47 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Potential SO_2 emissions are based on 400 hr/yr fuel oil combustion and natural gas combustion for the remainder of the year.

<u>Allowable Emissions</u> Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 2.50000 lb/hr	4. Equivalent Allowable Emissions: 2.50000 lb/hour 10.95 tons/year

5. Method of Compliance (limit to 60 characters):
Annual compliance demonstrated by calculation using sulfur content from gas analysis.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable based on current permit for natural gas firing.

<u>**Allowable Emissions**</u> Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.8 lb/MMBtu	4. Equivalent Allowable Emissions: 175.1200 lb/hour 35.0200 tons/year

5. Method of Compliance (limit to 60 characters):
Annual testing in accordance with EPA Method 6, conducted while the unit is operating within 10% of its rated capacity, to be required only if the Unit burns fuel oil for more than 400 hours in a calendar year.

1. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions request based on current permit limit. This allowable emissions limit is only applicable during fuel oil firing.

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

Potential/Fugitive Emissions – (16.5 MW Boiler Unit #6)

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:	
3. Potential Emissions: 1.1200 lb/hour 0.324 tons/year		4. Synthetically Limited? [Y]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: 0.76000 lb/1,000 gal Reference: AP-42		7. Emissions Method Code: 3
8. Calculation of Emissions (limit to 600 characters): Natural Gas 0.0236 lb/hr x ton/2,000 lb x 8,360 hrs/yr = 0.10 tons/yr Fuel Oil 0.76 lb/1,000 gal x 218.90 MMBtu/hr x 1,000 gal/148 MMBtu = 1.12 lb/hr 1.12 lb/hr x ton/2,000 lb x 400 hrs/yr = 0.224 tons/yr Potential- 0.10 tons/yr + 0.224 tons/yr = 0.324 tons.yr		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Potential VOC emissions are based on 400 hr/yr fuel oil combustion and natural gas combustion for the remainder of the year.		

Allowable Emissions Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
1. Requested Allowable Emissions and Units: 0.0236 lb/hr	4. Equivalent Allowable Emissions: 0.0236 lb/hour 0.100 tons/year
5. Method of Compliance (limit to 60 characters): Annual testing in accordance with EPA Method 25A, conducted while the unit is operating within 10% of its rated capacity.	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Allowable emissions based on 0.0236 lb/hr permit limit firing natural gas. This allowable emissions limit is only applicable during natural gas firing. Emissions are not limited during No. 2 fuel oil firing (Units 6, 7, and 8 may burn No. 2 fuel oil for up to a combined total of 400 hours per year).	

Allowable Emissions Allowable Emissions __2__ of __2__

Allowable Emissions Allowable Emissions __2__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
1. Requested Allowable Emissions and Units: 1.12 lb/hr	4. Equivalent Allowable Emissions: 1.12 lb/hour 0.100 tons/year

5. Method of Compliance (limit to 60 characters):
Annual testing in accordance with EPA Method 25A, conducted while the unit is operating within 10% of its rated capacity, to be required only if the Unit burns fuel oil for more than 400 hours in a calendar year.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Units 6, 7, and 8 limited to 400 hr/yr combined fuel oil combustion. Emissions are not limited when firing fuel oil.

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

<u>Potential/Fugitive Emissions</u> – (37.5 MW Boiler Unit #7)

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:	
3. Potential Emissions: 15.8800 lb/hour 34.9tons/year		4. Synthetically Limited? [Y]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: 5.00000 lb/1,000 gal Reference: AP-42		7. Emissions Method Code: 3

8. Calculation of Emissions (limit to 600 characters):
<u>Natural Gas</u>
7.589 lb/hr (air permit limit) x ton/2,000 lb x 8,360 hr/yr = 31.72 tons/yr
<u>Fuel Oil</u>
5.00 lb/1,000 gal x 470 MMBtu/hr x 1,000 gal/148 MMBtu = 15.88 lb/hr
15.88 lb/hr x ton/2,000 lb x 400 hr/yr = 3.18 tons/yr

<u>Potential</u>- 31.72 tons/yr + 3.18 tons/yr = 34.9 tons.yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Potential CO emissions are based on 400 hr/yr fuel oil combustion and natural gas combustion for the remainder of the year.

<u>Allowable Emissions</u> Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 7.58900 lb/hr	4. Equivalent Allowable Emissions: 7.5890 lb/hour 33.2400 tons/year

5. Method of Compliance (limit to 60 characters):
annual testing in accordance with EPA Method 10, conducted while the unit is operating within 10 % of its rated capacity.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions based on current permit limit. This allowable emissions limit is only applicable during natural gas firing. Emissions are not limited during No. 2 fuel oil firing (Units 6, 7, and 8 may burn No. 2 fuel oil for up to a combined total of 400 hours per year).

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 15.88 lb/hr	4. Equivalent Allowable Emissions: 15.88 lb/hour 3.18 tons/year
5. Method of Compliance (limit to 60 characters): Annual testing in accordance with EPA Method 10, conducted while the unit is operating within 10% of its rated capacity, to be required only if the Unit burns fuel oil for more than 400 hours in a calendar year.	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Units 6, 7, and 8 limited to 400 hr/yr combined fuel oil combustion. Emissions are not limited when firing fuel oil.	

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

<u>Potential/Fugitive Emissions</u> – (37.5 MW Boiler Unit #7)

1. Pollutant Emitted: NOx	2. Total Percent Efficiency of Control:
3. Potential Emissions: 212.7700 lb/hour 457.0500	4. Synthetically Limited? [Y]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 67.00000 lb/1,000 gal Reference: AP-42	7. Emissions Method Code: 3

8. Calculation of Emissions (limit to 600 characters):

<u>Natural Gas</u>
104.35 lb/hr (air permit limit) x ton/2,000 lb x 8,360 hr/yr = 436.18 tons/yr
<u>Fuel Oil</u>
67.00 lb/1,000 gal x 470 MMBtu/hr x 1,000 gal/148 MMBtu = 212.77 lb/hr
212.77 lb/hr x ton/2,000 lb x 400 hr/yr = 42.55tons/yr

<u>Potential</u>- 436.18 tons/yr + 42.55 tons/yr = 478.73 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Potential NOx emissions are based on 400 hr/yr fuel oil combustion and natural gas combustion for the remainder of the year.

<u>Allowable Emissions</u> Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 104.35000 lb/hr	4. Equivalent Allowable Emissions: 104.3500 lb/hour 457.0500 tons/year

5. Method of Compliance (limit to 60 characters):
annual testing in accordance with EPA Method 7, 7E, conducted while the unit is operating within 10% of its rated capacity.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions request based on current permit limit. This allowable emissions limit is only applicable during natural gas firing. Emissions are not limited during No. 2 fuel oil firing (Units 6, 7, and 8 may burn No. 2 fuel oil for up to a combined total of 400 hours per year).

<u>Allowable Emissions</u> Allowable Emissions __2__ of __2__

Emissions Unit Information Section 5 **of** 6

Pollutant Detail Information Page 4 **of** 12

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 212.77 lb/hr	4. Equivalent Allowable Emissions: 212.77 lb/hour 42.55 tons/year
5. Method of Compliance (limit to 60 characters): Annual testing in accordance with EPA Method 7E, conducted while the unit is operating within 10% of its rated capacity, to be required only if the Unit burns fuel oil for more than 400 hours in a calendar year.	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Units 6, 7, and 8 limited to 400 hr/yr combined fuel oil combustion. Emissions are not limited when firing fuel oil.	

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

Potential/Fugitive Emissions – (37.5 MW Boiler Unit #7)

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:	
3. Potential Emissions: 47.0000 lb/hour	11.77 tons/year	4. Synthetically Limited? [Y]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3	______ to ______ tons/year	
6. Emission Factor: 0.10000 lb/MMBtu Reference: Air Permit Limit		7. Emissions Method Code: 5

8. Calculation of Emissions (limit to 600 characters):
Natural Gas
0.568 lb/hr x ton/2,000 lb x 8,360 hr/yr = 2.37 tons/yr
Fuel Oil
0.1 lbs/MMBtu x 470 MMBtu/hr = 47.0 lb/hr
47.0 lb/hr x ton/2,000 lb x 400 hr/yr (Permit limit) = 9.4 tons/yr

Potential- 2.37 tons/yr + 9.4 tons/yr = 11.77 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Potential PM emissions are based on 400 hr/yr fuel oil combustion and natural gas combustion for the remainder of the year. Units 6, 7, and 8 are limited to a combined total of 400 hr/yr on No. 6 fuel oil. Therefore, synthetic limit based on 400 hr/yr operation on fuel oil.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.568 lb/hr	4. Equivalent Allowable Emissions: 0.568 lb/hour 2.4900 tons/year

5. Method of Compliance (limit to 60 characters):
annual testing in accordance with EPA Method 5, conducted while the unit is operating within 10% of its rated capacity.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions request based on current permit limit. This allowable emissions limit is only applicable during natural gas firing. Emissions are not limited during No. 2 fuel oil firing (Units 6, 7, and 8 may burn No. 2 fuel oil for up to a combined total of 400 hours per year).

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.10000 lb/MMBtu	4. Equivalent Allowable Emissions: 47.0000 lb/hour 9.4000 tons/year

5. Method of Compliance (limit to 60 characters):
annual testing in accordance with EPA Method 5, conducted while the unit is operating within 10% of its rated capacity, to be required only if Units 6, 7, and 8 burn fuel oil for more than 400 hours in a calendar year.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions request based on the unit's current permit limit and rule 62-296.405(1)(b), FAC. This allowable emissions limit is only applicable during fuel oil firing.

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

Potential/Fugitive Emissions – (37.5 MW Boiler Unit #7)

1. Pollutant Emitted: PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 47.0000 lb/hour 11.77 tons/year	4. Synthetically Limited? [Y]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.10000 lb/MMBtu Reference: Air Permit Limit	7. Emissions Method Code: 5

8. Calculation of Emissions (limit to 600 characters):
Natural Gas
0.568 lb/hr x ton/2,000 lb x 8,360 hr/yr = 2.37 tons/yr
Fuel Oil
0.1 lbs/MMBtu x 470 MMBtu/hr = 47.0 lb/hr
47.0 lb/hr x ton/2,000 lb x 400 hr/yr (Permit limit) = 9.4 tons/yr

Potential- 2.37 tons/yr + 9.4 tons/yr = 11.77 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Potential PM emissions are based on 400 hr/yr fuel oil combustion and natural gas combustion for the remainder of the year. Units 6, 7, and 8 are limited to a combined total of 400 hr/yr on No. 6 fuel oil. Therefore, synthetic limit based on 400 hr/yr operation on fuel oil.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.568 lb/hr	4. Equivalent Allowable Emissions: 0.568 lb/hour 2.4900 tons/year

5. Method of Compliance (limit to 60 characters):
annual testing in accordance with EPA Method 5, conducted while the unit is operating within 10% of its rated capacity.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions request based on current permit limit. This allowable emissions limit is only applicable during natural gas firing. Emissions are not limited during No. 2 fuel oil firing (Units 6, 7, and 8 may burn No. 2 fuel oil for up to a combined total of 400 hours per year).

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.10000 lb/MMBtu	4. Equivalent Allowable Emissions: 47.0000 lb/hour 9.4000 tons/year

5. Method of Compliance (limit to 60 characters):
annual testing in accordance with EPA Method 5, conducted while the unit is operating within 10% of its rated capacity, to be required only if Units 6, 7, and 8 burn fuel oil for more than 400 hours in a calendar year.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions request based on the unit's current permit limit and rule 62-296.405(1)(b), FAC. This allowable emissions limit is only applicable during fuel oil firing.

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

<u>Potential/Fugitive Emissions</u> – (37.5 MW Boiler Unit #7)

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 376.0000 lb/hour 85.65 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.80000 lbs/MMBtu Reference: Air Permit Limit	7. Emissions Method Code: 5

8. Calculation of Emissions (limit to 600 characters):
<u>Natural Gas</u>
2.5 lb/hr x ton/2,000 lb x 8,360 hr/yr = 10.45 tons/yr
<u>Fuel Oil</u>
0.80 lb/MMBtu x 470.00 MMBtu/hr = 376.00 lb/hr
376.0 lb/hr x ton/2,000 lb x 400 hr/yr (permit limit) = 75.2 tons/yr

<u>Potential</u>- 10.45 tons/yr + 75.2 tons/yr = 85.65 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Potential SO_2 emissions are based on No. 2 fuel oil combustion and the associated permit limit of 0.80 lbs/MMBtu (400 hours of operation). Synthetic limit is based on 400 hours per year operation on fuel oil.

<u>Allowable Emissions</u> Allowable Emissions __1__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 2.50000 lb/hr	4. Equivalent Allowable Emissions: 2.50000 lb/hour 10.95 tons/year

5. Method of Compliance (limit to 60 characters):
Annual compliance demonstrated by calculation using sulfur content from gas analysis.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions based on current permit limit when firing natural gas.

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.80000 lb/MMBtu	4. Equivalent Allowable Emissions: 376.0000 lb/hour 75.2000 tons/year

5. Method of Compliance (limit to 60 characters): annual testing in accordance with EPA Method 6, conducted while the unit is operating within 10% of its rated capacity, to be required only if Units 6, 7, and 8 burn fuel oil for more than 400 hours in a calender year.
1. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Allowable emissions request based on current permit limit. This allowable emissions limit is only applicable during fuel oil firing.

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

Potential/Fugitive Emissions – (37.5 MW Boiler Unit #7)

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 2.4100 lb/hour 1.59 tons/year	4. Synthetically Limited? [N]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.76000 lbs/1,000 gal Reference: AP-42	7. Emissions Method Code: 3

8. Calculation of Emissions (limit to 600 characters):
Natural Gas
0.266 lb/hr (emission rate while firing natural gas, based on AP-42 emissions factor of 1.4 lbs/MMCF) x ton/2,000 lb x 8,360 hrs/yr = 1.11 tons/yr
Fuel Oil
0.76 lb/1,000 gal x 470 MMBtu/hr x 1,000 gal/148 MMBtu = 2.41 lb/hr
2.41 lb/hr x 400 hr/yr x ton/2,000 lb = 0.48 tons/yr
Potential- 1.11 tons/yr + 0.48 tons/yr = 1.59 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Potential VOC emissions are based on 400 hr/yr fuel oil combustion and natural gas combustion for the remainder of the year.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
1. Requested Allowable Emissions and Units: 0.26600 lb/hr	4. Equivalent Allowable Emissions: 0.266 lb/hour 1.165 tons/year

5. Method of Compliance (limit to 60 characters):
Annual testing in accordance with EPA Method 25A, conducted while the unit is operating within 10% of its rated capacity.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions based on current permit limit. This allowable emissions limit is only applicable during natural gas firing. Emissions are not limited during No. 2 fuel oil firing (Units 6, 7, and 8 may burn No. 2 fuel oil for up to a combined total of 400 hours per year).

Allowable Emissions Allowable Emissions 2 of 2

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
1. Requested Allowable Emissions and Units: 2.41 lb/hr	4. Equivalent Allowable Emissions: 2.41 lb/hour 0.48 tons/year

5. Method of Compliance (limit to 60 characters):
VOC is considered in compliance when CO limit is being met.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Units 6, 7, and 8 limited to 400 hr/yr combined fuel oil combustion. Emissions are not limited when firing fuel oil.

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

Potential/Fugitive Emissions – (56.1 MW Boiler Unit #8)

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: 21.76 lb/hour 46.16 tons/year	4. Synthetically Limited? [Y]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 5.00000 lb/1,000 gal Reference: AP-42	7. Emissions Method Code: 3

8. Calculation of Emissions (limit to 600 characters):

Natural Gas
12.59 lb/hr x 6,642 hr/yr x ton/2,000 lb = 41.81 tons/yr
Fuel Oil
5 lb/1,000 gal x 644 MMBtu/hr x 1gal/148,000 Btu = 21.76 lb/hr
21.76 lb/hr x 400 hr/yr x ton/2,000 lb = 4.35 tons/yr

Potential- 41.81 tons/yr + 4.35 tons/yr = 46.16 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Potential CO emissions are based on 400 hr/yr fuel oil combustion and natural gas combustion 6,642 hr/yr. Units 6, 7, and 8 are limited to 4,534,930 MMBtu/yr combined and 45.3 tons CO combined.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 12.5900 lb/hr	4. Equivalent Allowable Emissions: 12.5900 lb/hour 45.3000 tons/year

5. Method of Compliance (limit to 60 characters):
Annual testing in accordance with EPA Method 10, conducted while the unit is Operating within 10% of its rated capacity.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions request based on current permit limits. This allowable emissions limit is only applicable during natural gas firing. Emissions are not limited during No. 2 fuel oil firing (Units 6, 7, and 8 may burn No. 2 fuel oil for up to a combined total of 400 hours per year).

Allowable Emissions Allowable Emissions 2 of 2

Emissions Unit Information Section 6 **of** 6

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Allowable Emissions Allowable Emissions __2__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 21.76 lb/hr	4. Equivalent Allowable Emissions: 21.76 lb/hour 4.35 tons/year

5. Method of Compliance (limit to 60 characters):
Annual testing in accordance with EPA Method 10, conducted while the unit is operating within 10% of its rated capacity, to be required only if the Unit burns fuel oil for more than 400 hours in a calendar year.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Units 6, 7, and 8 limited to 400 hr/yr combined fuel oil combustion. Emissions are not limited when firing fuel oil.

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

Potential/Fugitive Emissions – (56.1 MW Boiler Unit #8)

1. Pollutant Emitted: NOx	2. Total Percent Efficiency of Control:
3. Potential Emissions: 193.2 lb/hour 466.37 tons/year	4. Synthetically Limited? [Y]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 67.00000 lb/1,000 gal Reference: AP-42	7. Emissions Method Code: 3

8. Calculation of Emissions (limit to 600 characters):
Natural Gas
0.2 lb/MMBtu x 644 MMBtu/hr = 128.8 lb/hr
128.8 lb/hr x 6,642 hr/yr x ton/2,000 lb = 427.73 tons/yr
Fuel Oil
0.3 lb/MMBtu x 644 MMBtu/hr = 193.2 lb/hr
193.2 lb/hr x 400 hr/yr x ton/2,000 lb = 38.64 tons/yr
Potential- 427.73 tons/yr + 38.64 tons/yr = 466.37 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Potential NOx emissions are based on 400 hr/yr fuel oil combustion and natural gas combustion for the remainder of the year.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
1. Requested Allowable Emissions and Units: 0.2 lb/MMBtu	4. Equivalent Allowable Emissions: 128.8 lb/hour 427.73 tons/year

5. Method of Compliance (limit to 60 characters):
Annual testing in accordance with EPA Method 7, 7E, conducted while the unit is operating within 10% of it's rated capacity.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions based on current permit limits. This allowable emissions limit is only applicable during natural gas firing. Emissions are not limited during No. 2 fuel oil firing (Units 6, 7, and 8 may burn No. 2 fuel oil for up to a combined total of 400 hrs/yr.

Emissions Unit Information Section 6 **of** 6

Pollutant Detail Information Page 4 **of** 12

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
1. Requested Allowable Emissions and Units: 0.3 lb/MMBtu	4. Equivalent Allowable Emissions: 193.2 lb/hour 38.64 tons/year
5. Method of Compliance (limit to 60 characters): Annual testing in accordance with EPA Method 7E, conducted while the unit is operating within 10% of its rated capacity, to be required only if the Unit burns fuel oil for more than 400 hours in a calendar year.	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Units 6, 7, and 8 limited to 400 hr/yr combined fuel oil combustion. Emissions are not limited when firing fuel oil.	

(Regulated Emissions Units - Emissions-Limited and Preconstruction Review Pollutants Only)

Potential/Fugitive Emissions – (56.1 MW Boiler Unit #8)

1. Pollutant Emitted: PM	2. Total Percent Efficiency of Control:
3. Potential Emissions: 64.4 lb/hour 16.02 tons/year	4. Synthetically Limited? [Y]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.10000 lb/MMBtu Reference: Air Permit Limit	7. Emissions Method Code: 5
8. Calculation of Emissions (limit to 600 characters): Natural Gas 4,277,330 MMBtu/yr x 1 hr/644 MMBtu x 0.945 lb/hr x ton/2,000 lb = 3.14 tons/yr Fuel Oil 0.1 lb/MMBtu x 644 MMBtu/hr = 64.4 lb/hr 64.4 lb/hr x 400 hr/yr x ton/2,000 lb = 12.88 tons/yr Potential- 3.14 tons/yr + 12.88 tons/yr = 16.02 tons/yr	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Potential PM emissions are based on 400 hr/yr fuel oil combustion and natural gas combustion for the remainder of the year. Units 6, 7, and 8 are limited to a combined total of 400 hr/yr on No. 2 fuel oil. Also Units 6, 7, and 8 are limited to a combined heat input of 4,534,930 MMBtu/yr	

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.94500 lb/hr	4. Equivalent Allowable Emissions: 0.9450 lb/hour 4.14 tons/year
5. Method of Compliance (limit to 60 characters): Annual testing in accordance with EPA Method 5, conducted while the unit is operating within 10% of its rated capacity.	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Allowable emissions request based on current permit limit. This allowable emissions limit is only applicable during natural gas firing.	

Allowable Emissions Allowable Emissions 2 of 2

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.10000 lbs/MMBtu	4. Equivalent Allowable Emissions: 64.400 lb/hour 12.88 tons/year

5. Method of Compliance (limit to 60 characters):
Annual testing in accordance with EPA Method 5, conducted while the unit is operating within 10% of its rated capacity, to be required only if Units 6, 7, and 8 burn fuel oil for more than 400 hours in a calendar year.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions request based on the unit's current permit limit, 40CFR60.42 and Rule 62-296.405(1)(b), FAC. This allowable emissions limit is only applicable during fuel oil firing.

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

Potential/Fugitive Emissions – (56.1 MW Boiler Unit #8)

1. Pollutant Emitted: PM-10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 64.4 lb/hour 16.02 tons/year	4. Synthetically Limited? [Y]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.10000 lb/MMBtu Reference: Air Permit Limit	7. Emissions Method Code: 5

8. Calculation of Emissions (limit to 600 characters):
Natural Gas
4,277,330 MMBtu/yr x 1 hr/644 MMBtu x 0.945 lb/hr x ton/2,000 lb = 3.14 tons/yr
Fuel Oil
0.1 lb/MMBtu x 644 MMBtu/hr = 64.4 lb/hr
64.4 lb/hr x 400 hr/yr x ton/2,000 lb = 12.88 tons/yr
Potential- 3.14 tons/yr + 12.88 tons/yr = 16.02 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Potential PM emissions are based on 400 hr/yr fuel oil combustion and natural gas combustion for the remainder of the year. Units 6, 7, and 8 are limited to a combined total of 400 hr/yr on No. 2 fuel oil. Also Units 6, 7, and 8 are limited to a combined heat input of 4,534,930 MMBtu/yr

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.94500 lb/hr	4. Equivalent Allowable Emissions: 0.9450 lb/hour 4.14 tons/year

5. Method of Compliance (limit to 60 characters):
Annual testing in accordance with EPA Method 5, conducted while the unit is operating within 10% of its rated capacity.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions request based on current permit limit. This allowable emissions limit is only applicable during natural gas firing.

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.10000 lbs/MMBtu	4. Equivalent Allowable Emissions: 64.400 lb/hour 12.88 tons/year

5. Method of Compliance (limit to 60 characters):
Annual testing in accordance with EPA Method 5, conducted while the unit is operating within 10% of its rated capacity, to be required only if Units 6, 7, and 8 burn fuel oil for more than 400 hours in a calendar year.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions request based on the unit's current permit limit, 40CFR60.42 and Rule 62-296.405(1)(b), FAC. This allowable emissions limit is only applicable during fuel oil firing.

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

Potential/Fugitive Emissions – (56.1 MW Boiler Unit #8)

1. Pollutant Emitted: SO_2	2. Total Percent Efficiency of Control:
3. Potential Emissions: 515.20 lb/hour 111.34 tons/year	4. Synthetically Limited? [Y]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: 0.80000 lb/MMBtu Reference: Air Permit Limit	7. Emissions Method Code: 5

8. Calculation of Emissions (limit to 600 characters):
Natural Gas
4,277,330 MMBtu/yr x 1 hr/644 MMBtu x 2.5 lb/hr x ton/2,000 lb = 8.30 tons/yr
Fuel Oil
0.80 lb/MMBtu (permit limit) x 644 MMBtu/hr = 515.20 lb/hr
515.20 lb/hr x ton/2,000 lb x 400 hr/yr (permit limit) = 103.04 tons/yr

Potential- 8.30 tons/yr + 103.04 tons/yr = 111.34 tons/yr

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):

Potential SO_2 emissions are based on 400 hr/yr fuel oil combustion and natural gas combustion for the remainder of the year. No. 2 fuel oil may only be burned in Units 6, 7, and 8 as an emergency backup fuel for a total of 400 hr/yr.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 2.500 lb/hr	4. Equivalent Allowable Emissions: 2.500 lb/hour 10.95 tons/year

5. Method of Compliance (limit to 60 characters):
Annual testing in accordance with EPA Method 6, conducted while the unit is operating Within 10% of its rated capacity.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions request based on current permit limit. This allowable emissions limit Is only applicable during natural gas firing.

Allowable Emissions Allowable Emissions 2 of 2

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 0.80000 lbs/MMBtu	4. Equivalent Allowable Emissions: 515.20 lb/hour 103.04 tons/year

5. Method of Compliance (limit to 60 characters):
annual testing in accordance with EPA Method 6, conducted while the unit is operating within 10% of its rated capacity, to be required only if Units 6, 7, and 8 burn fuel oil for more than 400 hours in a calender year.

1. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):

Allowable emissions request based on current permit limit. This allowable emissions limit is only applicable during fuel oil firing.

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

<u>Potential/Fugitive Emissions</u> – (56.1 MW Boiler Unit #8)

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:	
3. Potential Emissions: 3.1400 lb/hour 2.09 tons/year		4. Synthetically Limited? [Y]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: 0.76000 lb/1,000 gal Reference: AP-42		7. Emissions Method Code: 3
8. Calculation of Emissions (limit to 600 characters): <u>Natural Gas</u> 4,277,330 MMBtu/yr x 1 hr/644 MMBtu x 0.441 lb/hr x ton/2,000 lb = 1.46 tons/yr <u>Fuel Oil</u> 0.76 lb/1,000 gal x 611.0 MMBtu/hr x 1,000 gal/148 MMBtu = 3.14 lb/hr 3.14 lb/hr x ton/2,000 lb x 400 hr/yr (permit limit) = 0.63 tons/yr <u>Potential</u>- 1.46 tons/yr + 0.63 tons/yr = 2.09 tons/yr		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Potential VOC emissions are based on 400 hr/yr fuel oil combustion and natural gas combustion for the remainder of the year. Potential annual VOC emissions are based on firing natural gas and the current air permit which synthetically limits the total annual heat input for Units 6, 7, and 8 to less than or equal to 4,534,930 MM Btu/yr.		

<u>Allowable Emissions</u> Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
1. Requested Allowable Emissions and Units: 0.44100 lbs/hr	4. Equivalent Allowable Emissions: 0.44100 lb/hour 1.6400 tons/year
5. Method of Compliance (limit to 60 characters): Annual testing in accordance with EPA Method 25A, conducted while the unit is operating within 10% of its rated capacity.	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Allowable emissions based on current permit limit. This allowable emissions limit is only applicable during natural gas firing. Emissions are not limited during No. 2 fuel oil firing (Units 6, 7, and 8 may burn No. 2 fuel oil for up to a combined total of 400 hours per year).	

Emissions Unit Information Section 6 **of** 6

Pollutant Detail Information Page 12 **of** 12

Allowable Emissions Allowable Emissions __2__ of __2__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
1. Requested Allowable Emissions and Units: 3.14 lbs/hr	4. Equivalent Allowable Emissions: 3.14 lb/hour 0.63 tons/year
5. Method of Compliance (limit to 60 characters): VOC is considered in compliance when CO limit is being met.	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Allowable emissions based on current permit limit. This allowable emissions limit is only applicable during natural gas firing. Emissions are not limited during No. 2 fuel oil firing (Units 6, 7, and 8 may burn No. 2 fuel oil for up to a combined total of 400 hours per year). Units 6, 7, and 8 are also limited to a combined heat input of 4,534,930 MMBtu/yr. Emissions not limited when firing fuel oil.	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)
(2.75 MW West Diesel #1)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: VE	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: 100 % Maximum Period of Excess Opacity Allowed: 60 min/hour	
4. Method of Compliance: Annual testing in accordance with EPA Method 9, conducted while the source is operating within 10% of the rated capacity.	
5. Visible Emissions Comment (limit to 200 characters): Requested exceptional condition opacity limit is to allow for start up, malfunction, and low load operation required for testing and for operation after overhaul. General emission standard under 62-296.310(2)(a), FAC. As per 62-210.700(1), FAC excess emissions during startup, shutdown, or malfunction shall be permitted but in no case exceed two hours in any 24 hour period.	

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

(2.75 MW East Diesel #2)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype: VE	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: 100 % Maximum Period of Excess Opacity Allowed: 60 min/hour	
4. Method of Compliance: Annual testing in accordance with EPA Method 9, conducted while the source is operating within 10% of the rated capacity.	
5. Visible Emissions Comment (limit to 200 characters): Requested exceptional condition opacity limit is to allow for start up, malfunction, and low load operation required for testing and for operation after overhaul. General emission standard under 62-296.310(2)(a), FAC. As per 62-210.700(1), FAC excess emissions during startup, shutdown, or malfunction shall be permitted but in no case exceed two hours in any 24 hour period.	

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

(36.1 Combined Cycle Gas Turbine Unit #9)

Visible Emissions Limitation: Visible Emissions Limitation __1__ of __1__

1. Visible Emissions Subtype: VE	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 15 % Exceptional Conditions: 20 % Maximum Period of Excess Opacity Allowed: 10 min/hour	
4. Method of Compliance: Annual testing in accordance with EPA Method 9, conducted while the source is operating within 10% of the rated capacity.	
5. Visible Emissions Comment (limit to 200 characters): Visible emissions limit based on current permit limit. As per 62-210.700(1), FAC, excess emissions during startup, shutdown, or malfunction shall be permitted but in no case exceed two hours in any 24 hour period.	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)
(16.5 MW Boiler Unit #6)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: VE	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: 5 % Exceptional Conditions: 15 % Maximum Period of Excess Opacity Allowed: 10 min/hour	
4. Method of Compliance: Annual testing in accordance with EPA Method 9, conducted while the source is operating within 10% of the rated capacity.	
1. Visible Emissions Comment (limit to 200 characters): Visible emissions are limited by the current air permit. Visible emissions may not exceed 5% opacity while firing natural gas. Requested exceptional conditions of 15% f or 10 minutes per hour to allow for start up, shut down, or any malfunctions. As per 62-210.700(1), FAC, excess emissions during startup, shutdown, or malfunction shall be permitted but in no case exceed two hours in any 24 hour period.	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: VE	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: 40 % Maximum Period of Excess Opacity Allowed: 2 min/hour	
4. Method of Compliance: Annual testing in accordance with EPA Method 9, conducted while the source is operating within 10% of the rated capacity (only if fuel oil usage by Units 6, 7, and 8 exceeds 400 hours in any calendar year).	
1. Visible Emissions Comment (limit to 200 characters): The current air permit and 62-296.405(1)(a), FAC, limits visible emissions. Visible emissions may not exceed 20% opacity when burning fuel oil, except for one, two-minute period per hour during which opacity shall not exceed 40%. As per 62-210.700(1), FAC, excess emissions during startup, shutdown, or malfunction shall be permitted but in no case exceed two hours in any 24 hour period.	

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

(37.5 MW Boiler Unit #7)

Visible Emissions Limitation: Visible Emissions Limitation __1__ of __2__

1. Visible Emissions Subtype: VE	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: 5 % Exceptional Conditions: 15 % Maximum Period of Excess Opacity Allowed: 10 min/hour	
4. Method of Compliance: Annual testing in accordance with EPA Method 9, conducted while the source is operating within 10% of the rated capacity.	
1. Visible Emissions Comment (limit to 200 characters): The current air permit limits VE emissions. Visible emissions may not exceed 5% opacity while firing natural gas. Requested exceptional conditions of 15% for 10 minutes per hour to allow for start up, shut down, or any malfunctions. As per 62-210.700(1), FAC, excess emissions during startup, shutdown, or malfunction shall be permitted but in no case exceed two hours in any 24 hour period.	

Visible Emissions Limitation: Visible Emissions Limitation __2__ of __2__

1. Visible Emissions Subtype: VE	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: 40 % Maximum Period of Excess Opacity Allowed: 2 min/hour	
4. Method of Compliance: Annual testing in accordance with EPA Method 9, conducted while the source is operating within 10% of the rated capacity (only if fuel oil usage by Units 6, 7, and 8 exceeds 400 hours in any calendar year).	
1. Visible Emissions Comment (limit to 200 characters): The current air permit and 62-296.405(1)(a), FAC, limits visible emissions. Visible emissions may not exceed 20% opacity when burning fuel oil, except for one, two-minute period per hour during which opacity shall not exceed 40%. As per 62-210.700(1), FAC, excess emissions during startup, shutdown, or malfunction shall be permitted but in no case exceed two hours in any 24 hour period.	

H. VISIBLE EMISSIONS INFORMATION
(Only Regulated Emissions Units Subject to a VE Limitation)
(56.1 MW Boiler Unit #8)

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: VE	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: 5 % Exceptional Conditions: 15 % Maximum Period of Excess Opacity Allowed: 10 min/hour	
4. Method of Compliance: Annual testing in accordance with EPA Method 9, conducted while the source is operating within 10% of the rated capacity.	
1. Visible Emissions Comment (limit to 200 characters): The current air permit limits visible emissions to less than or equal to 5% opacity while firing natural gas. Requested exceptional conditions of 15% for 10 minutes per hour to allow for start up, shut down, or any malfunctions. As per 62-210.700(1), FAC, excess emissions during startup, shutdown, or malfunction shall be permitted but in no case exceed two hours in any 24 hour period.	

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: VE	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: 20 % Exceptional Conditions: 27 % Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance: Annual testing in accordance with EPA Method 9, conducted while the source is operating within 10% of the rated capacity (only if fuel oil usage by Units 6, 7, and 8 exceeds 400 hours in any calendar year).	
1. Visible Emissions Comment (limit to 200 characters): The current air permit and 62-296.405(1)(a), FAC, limits visible emissions to less than or equal to 20% opacity when burning fuel oil, except for one, six-minute period per hour during which opacity shall not exceed 27%. As per 62-210.700(1), FAC, excess emissions during startup, shutdown, or malfunction shall be permitted but in no case exceed two hours in any 24 hour period.	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)
(31.6 MW Combined Cycle Gas Turbine Unit #9)

Continuous Monitoring System: Continuous Monitor __1__ of __1__

1. Parameter Code: WTF	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: G.E. Model Number: Speedtronic Mark IV	Serial Number:
5. Installation Date: 1/2/88	6. Performance Specification Test Date: 11/9/89
7. Continuous Monitor Comment (limit to 200 characters): Continuous monitoring of the ratio of water to fuel is a requirement of 40CFR60.334 and the current air permit.	

I. CONTINUOUS MONITOR INFORMATION
(Only Regulated Emissions Units Subject to Continuous Monitoring)
(56.1 MW Boiler Unit #8)

Continuous Monitoring System: Continuous Monitor __1__ of __2__

1. Parameter Code: NOx	2. Pollutant(s): NOx
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Thermo Environmental Model Number: 42D	Serial Number: 47986-279
5. Installation Date: 1/7/94	6. Performance Specification Test Date: 1/11/94
7. Continuous Monitor Comment (limit to 200 characters): This NOx monitor meets the requirements of 40CFR75, Regulations for CEMs under acid Rain Requirements, 40CFR60, and current air permit. Use of the old NOx and O_2 monitors under 40CFR60 will be discontinued.	

Continuous Monitoring System: Continuous Monitor __2__ of __2__

1. Parameter Code: CO_2	2. Pollutant(s): CO_2
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Thermo Environmental Model Number: 41H	Serial Number: 41H-48183
5. Installation Date: 1/7/94	6. Performance Specification Test Date: 1/11/94
7. Continuous Monitor Comment (limit to 200 characters): CO_2 monitor required by 40CFR75.	

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

Supplemental Requirements – (2.75 MW West Diesel #1)

1. Process Flow Diagram [X] Attached, Document ID: Figure 3 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Attachment B [ ] 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: Attachment E [ ] 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
    [X] Attached, Document ID: Attachment F [ ] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [ ] 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

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

Supplemental Requirements – (2.75 MW East Diesel #2)

1. Process Flow Diagram [X] Attached, Document ID: Figure 4 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Attachment B [ ] 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: Attachment E [ ] 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 [X] Attached, Document ID: Attachment F [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] 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

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

Supplemental Requirements – (31.6 MW Combined Cycle Gas Turbine Unit #9)

1.	Process Flow Diagram [X] Attached, Document ID: Figure 5 [ ] Not Applicable [ ] Waiver Requested
2.	Fuel Analysis or Specification [X] Attached, Document ID: Attachment B [ ] Not Applicable [ ] Waiver Requested
3.	Detailed Description of Control Equipment [X] Attached, Document ID: Attachment C [ ] Not Applicable [ ] Waiver Requested
4.	Description of Stack Sampling Facilities [X] Attached, Document ID: Attachment D [ ] 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: Attachment E [ ] 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 [X] Attached, Document ID: ftpcalm.wk4 [ ] 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: Attachment F [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] 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

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

Supplemental Requirements – (16.5 MW Boiler Unit #6)

1. Process Flow Diagram [X] Attached, Document ID: Figure 6 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Attachment B [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: Attachment C [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: Attachment D [ ] 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: Attachment E [ ] 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
    [X] Attached, Document ID: ftpcalm.wk4 [ ] 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: Attachment F [ ] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [ ] 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

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

Supplemental Requirements – (37.5 MW Boiler Unit #7)

1. Process Flow Diagram [X] Attached, Document ID: Figure 7 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Attachment B [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: Attachment C [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: Attachment D [ ] 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: Attachment E [ ] 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
    [X] Attached, Document ID: ftpcalm.wk4 [ ] 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: Attachment F [ ] Not Applicable

14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [ ] 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

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

Supplemental Requirements – (37.5 MW Boiler Unit #7)

1. Process Flow Diagram [X] Attached, Document ID: Figure 7 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Attachment B [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: Attachment C [ ] Not Applicable [ ] Waiver Requested
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5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:_______________ [X] Not Applicable
6. Procedures for Startup and Shutdown [X] Attached, Document ID: Attachment E [ ] Not Applicable [ ] Waiver Requested
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13. Identification of Additional Applicable Requirements
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14. Compliance Assurance Monitoring Plan
    [ ] Attached, Document ID:________ [ ] Not Applicable

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

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    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

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

Supplemental Requirements – (37.5 MW Boiler Unit #7)

1. Process Flow Diagram [X] Attached, Document ID: Figure 7 [ ] Not Applicable [ ] Waiver Requested	
2. Fuel Analysis or Specification [X] Attached, Document ID: Attachment B [ ] Not Applicable [ ] Waiver Requested	
3. Detailed Description of Control Equipment [X] Attached, Document ID: Attachment C [ ] Not Applicable [ ] Waiver Requested	
4. Description of Stack Sampling Facilities [X] Attached, Document ID: Attachment D [ ] Not Applicable [ ] Waiver Requested	
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________________ [X] Not Applicable	
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Additional Supplemental Requirements for Title V Air Operation Permit Applications

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12. Alternative Modes of Operation (Emissions Trading)
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13. Identification of Additional Applicable Requirements
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14. Compliance Assurance Monitoring Plan
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    [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
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    [ ] 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

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

Supplemental Requirements – (37.5 MW Boiler Unit #7)

1. Process Flow Diagram [X] Attached, Document ID: Figure 7 [ ] Not Applicable [ ] Waiver Requested	
2. Fuel Analysis or Specification [X] Attached, Document ID: Attachment B [ ] Not Applicable [ ] Waiver Requested	
3. Detailed Description of Control Equipment [X] Attached, Document ID: Attachment C [ ] Not Applicable [ ] Waiver Requested	
4. Description of Stack Sampling Facilities [X] Attached, Document ID: Attachment D [ ] Not Applicable [ ] Waiver Requested	
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Additional Supplemental Requirements for Title V Air Operation Permit Applications

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    [ ] Attached, Document ID:________ [X] Not Applicable

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

14. Compliance Assurance Monitoring Plan
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    [X] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
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    [ ] 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

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

Supplemental Requirements – (56.1 MW Boiler Unit #8)

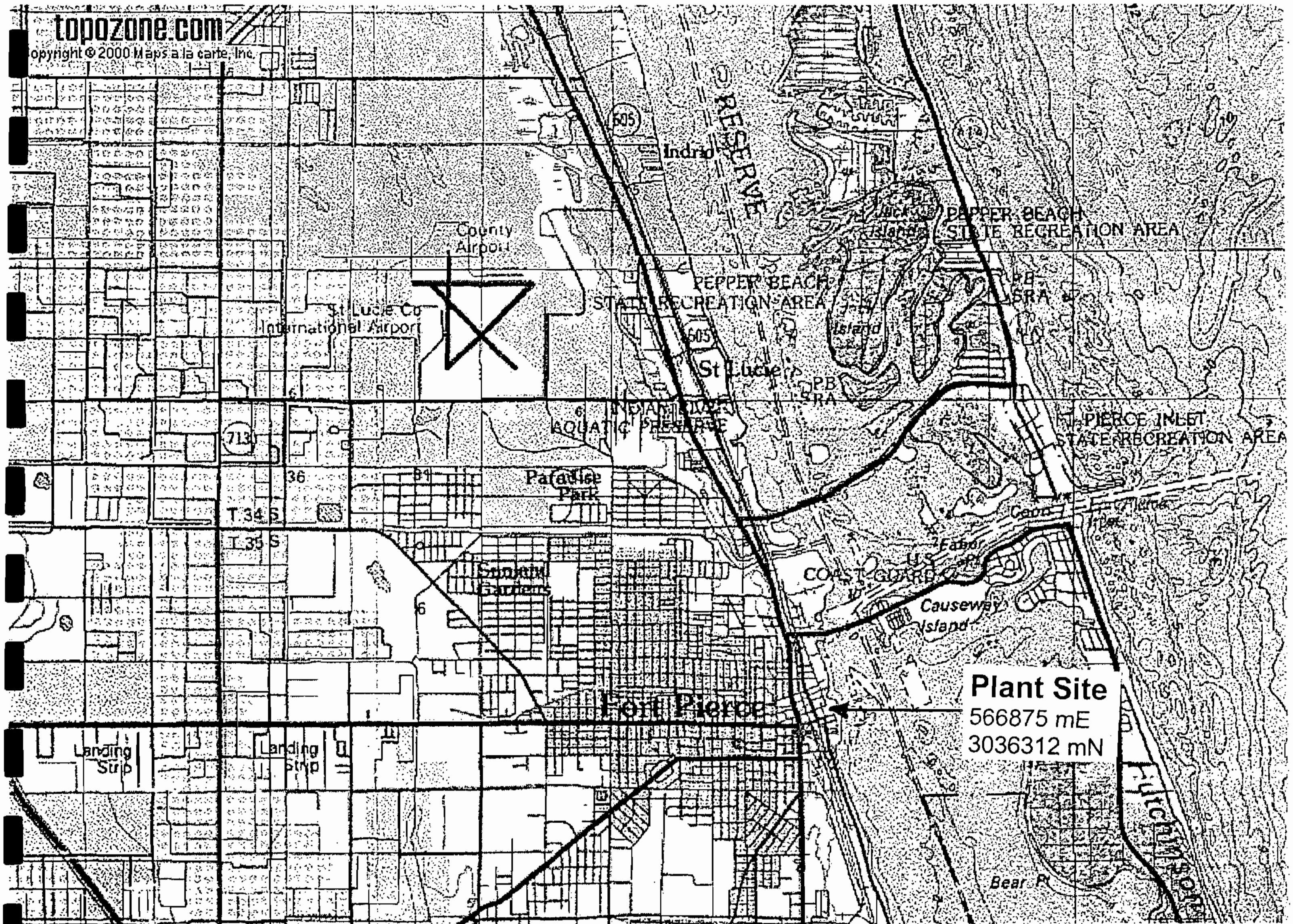
1. Process Flow Diagram [X] Attached, Document ID: Figure 8 [ ] Not Applicable [ ] Waiver Requested	
2. Fuel Analysis or Specification [X] Attached, Document ID: Attachment B [ ] Not Applicable [ ] Waiver Requested	
3. Detailed Description of Control Equipment [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested	
4. Description of Stack Sampling Facilities [X] Attached, Document ID: Attachment D [ ] 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: Attachment E [ ] 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 [X] Attached, Document ID: ftpcalm.wk4 [ ] 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: Attachment F [ ] Not Applicable
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [ ] 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: Attachment G [ ] 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

ATTACHMENTS AND FIGURES

Target is UTM 17 566626E 3035890N - **FORT PIERCE** quad [Quad Info]



APPENDIX J

BEST AVAILABLE COPY

SITE PLAN OF H.D. KING PLANT

SITE ARRANGEMENT

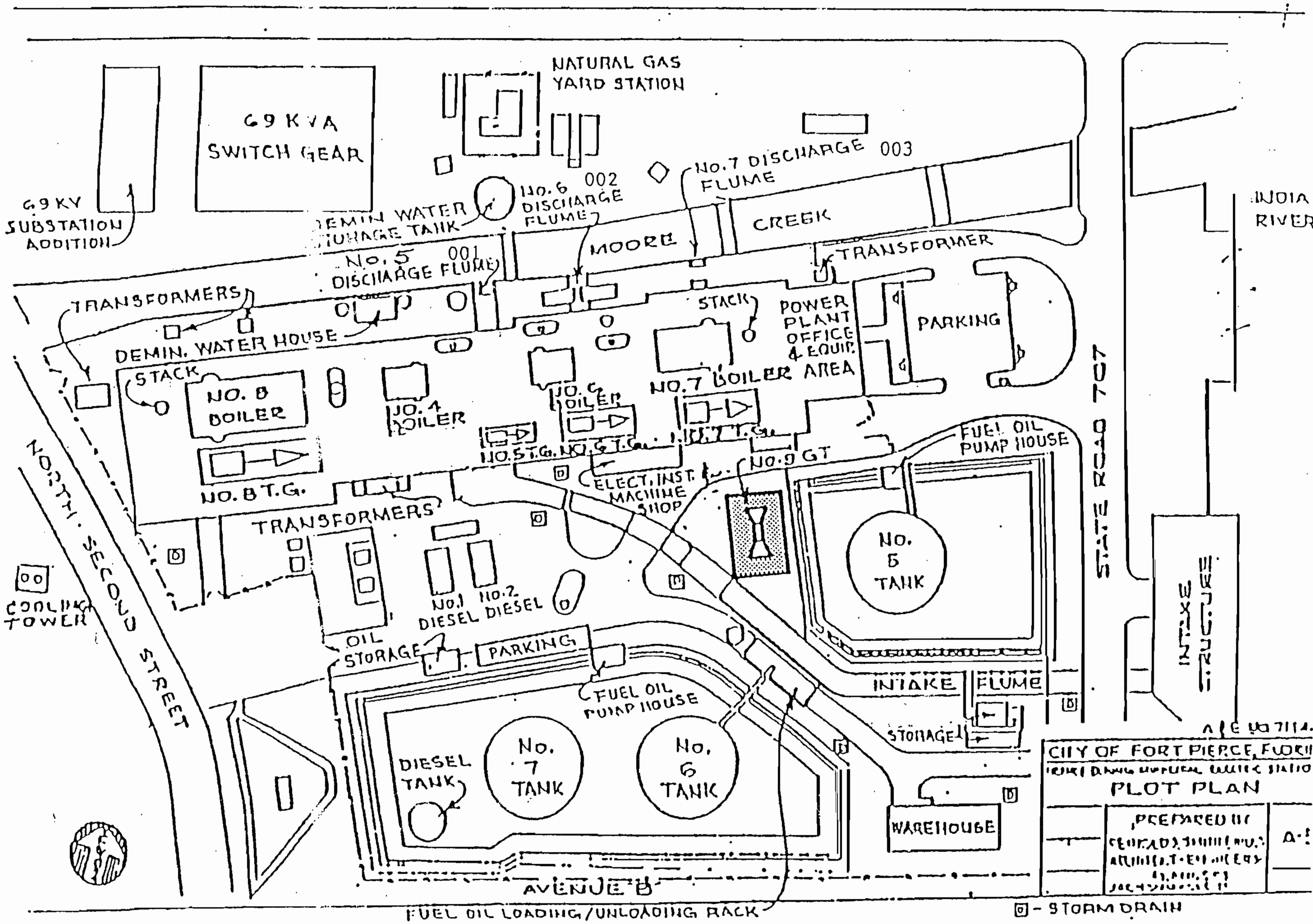
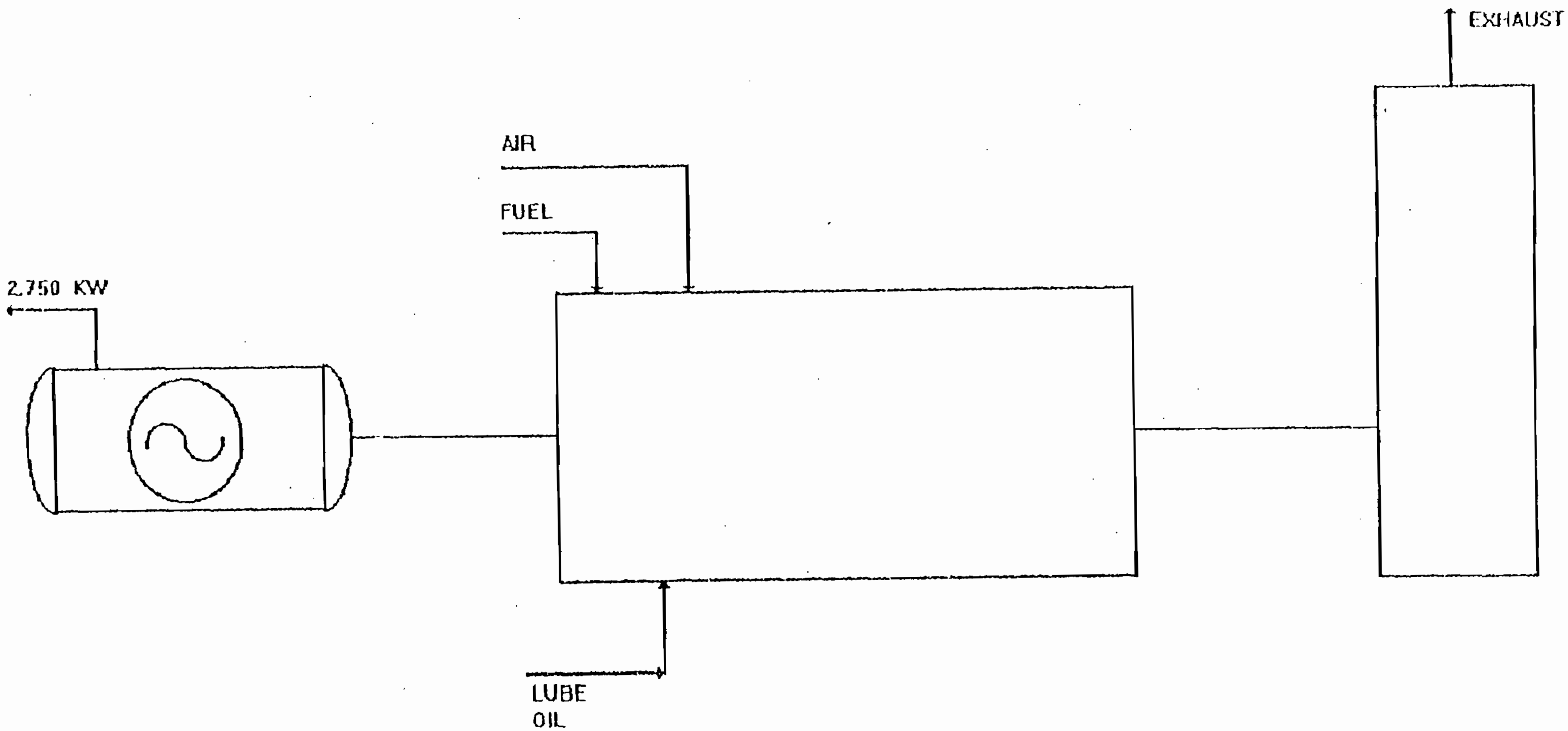


Figure 2

PROCESS FLOW DIAGRAM

H. D. KING DIESEL UNIT #1



FORT PIERCE UTILITIES AUTHORITY
FORT PIERCE, FLORIDA
DATE: 6-6-95

Figure 3

BEST AVAILABLE COPY

PROCESS FLOW DIAGRAM

H. D. KING DIESEL UNIT #2

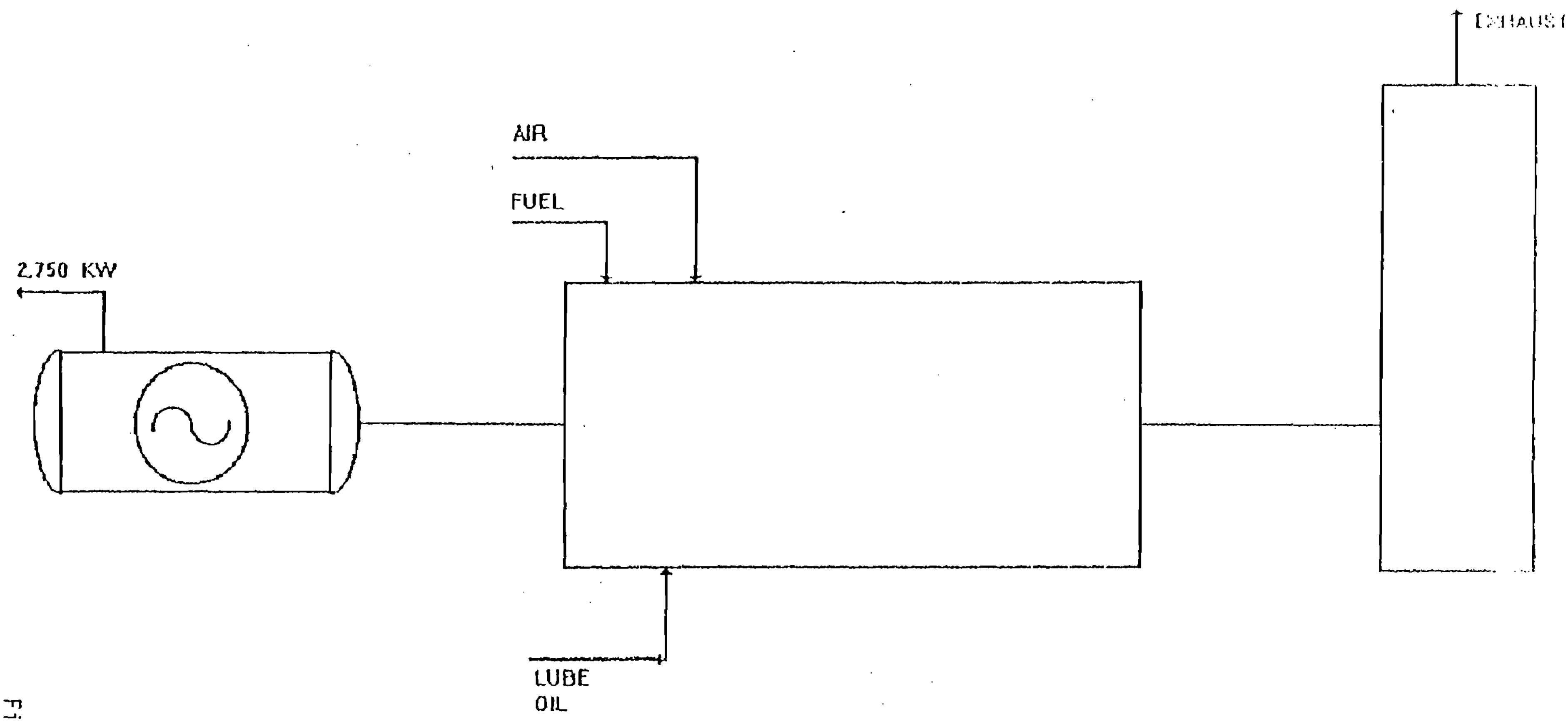
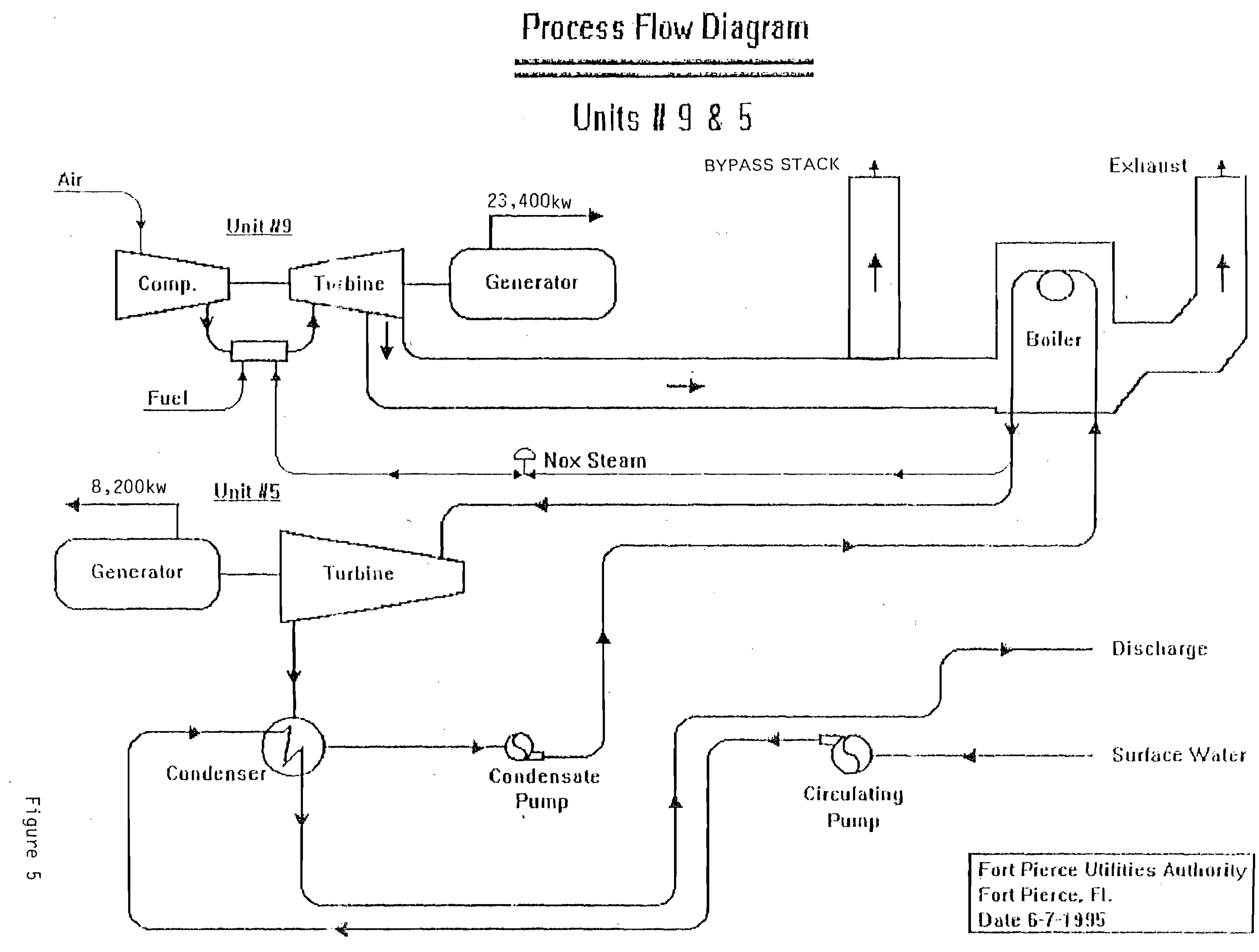


Figure 4

FORT PIERCE UTILITIES AUTHORITY
FORT PIERCE, FLORIDA
DATE: 6-6-95

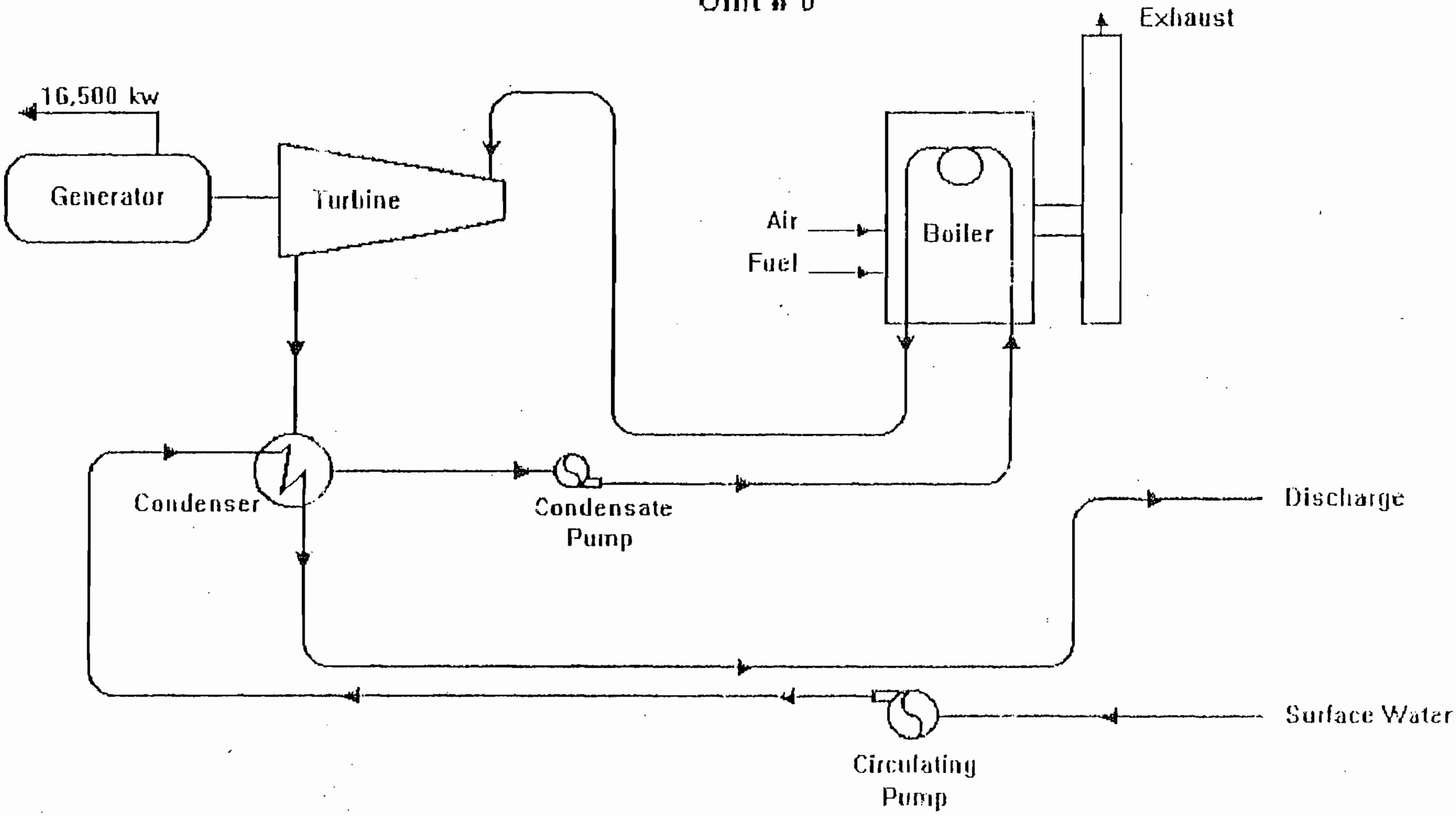


Process Flow Diagram
Units # 9 & 5
BYPASS STACK
Exhaust
Air
23,400kw
Unit #9
Comp.
Turbine
Generator
Boiler
Fuel
Nox Steam
8,200kw
Unit #5
Generator
Turbine
Discharge
Surface Water
Condenser
Condensate Pump
Circulating Pump
Fort Pierce Utilities Authority
Fort Pierce, Fl.
Date 6-7-1995

Figure 5

Process Flow Diagram

Unit # 6



Fort Pierce Utilities Authority
Fort Pierce, Fl.
Date 6-7-1995

Figure 6

Process Flow Diagram

Unit # 7

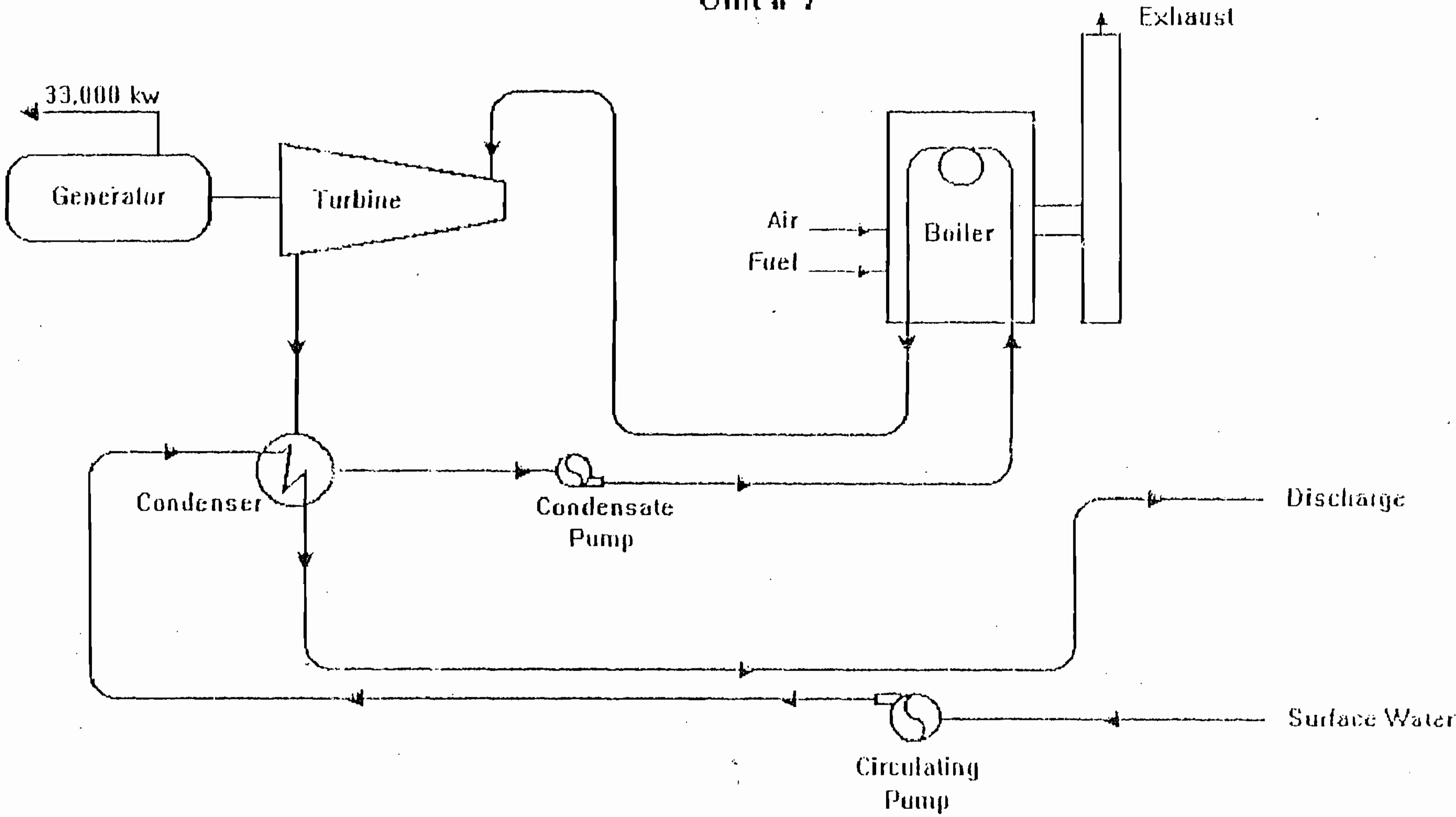
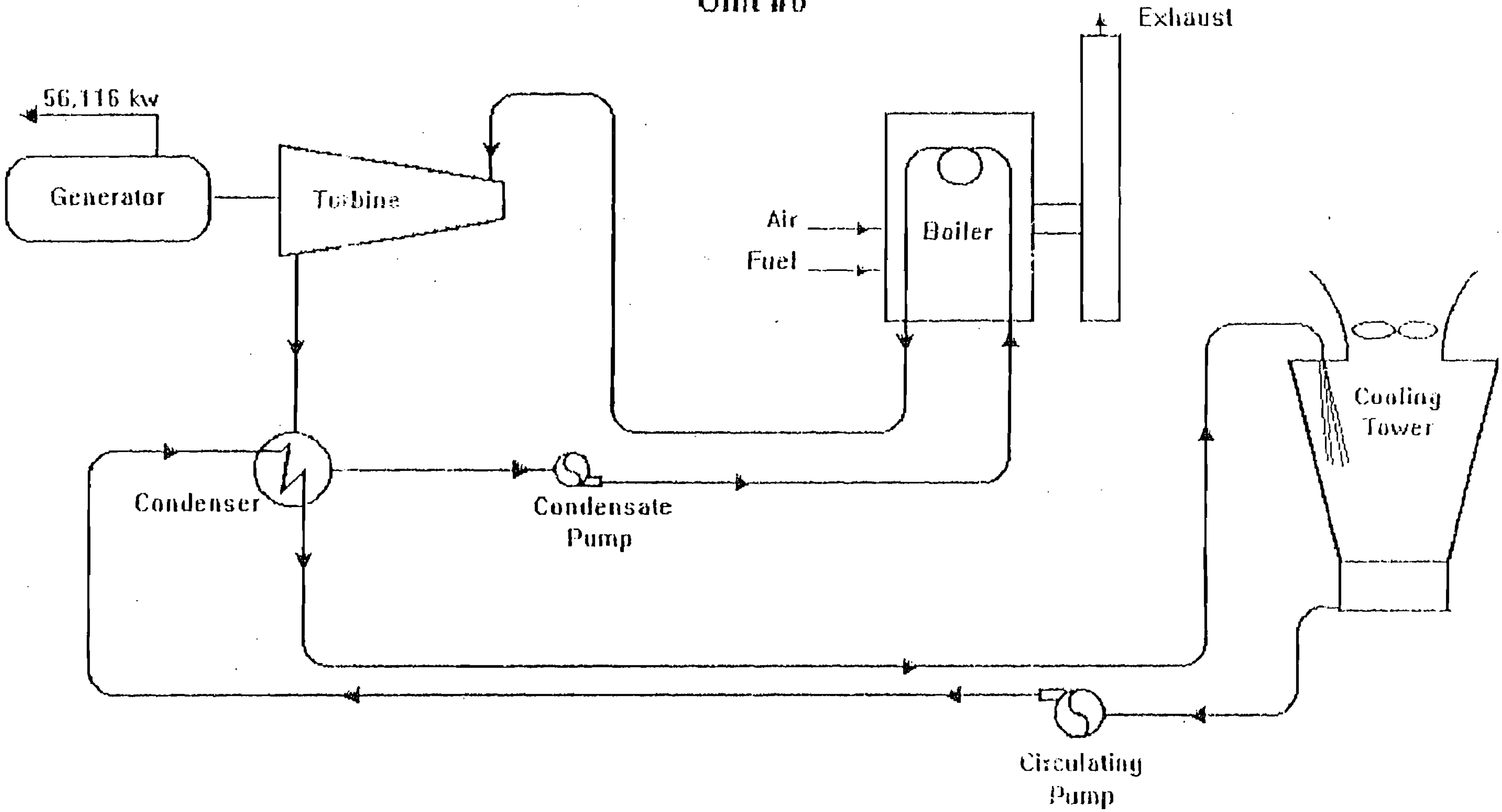


Figure 7

Fort Pierce Utilities Authority
Fort Pierce, Fl.
Date 6-7-1995

Process Flow Diagram

Unit #8



Fort Pierce Utilities Authority
Fort Pierce, Fl.
Date 6-7-1995

Figure 8

Attachment A

COMPLIANCE STATEMENT

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

Thomas W. Richards
Director of Operations

Attachment B

FUEL ANALYSES

FLORIDA GAS TRANSMISSION COMPANY

Spot Analysis of Natural Gas for Delivery in Florida

DATE: April 25, 1995
TIME: 11:48

Component Name	Mole %
Hexane	0.054
Propane	0.390
Isobutane	0.101
n-Butane	0.080
Isopentane	0.031
n-Pentane	0.018
Nitrogen	0.349
Methane	96.060
CO_2	0.746
Ethane	2.171
Totals	100.000

Dry Btu/cf @ 14.730 psia and 60°F = 1033.7
Real Relative Density = 0.5829

Total Sulfur	0.16 Gr/Ccf
Total Sulfur D/S	0.35 Gr/Ccf
H^2S	0.04 Gr/Ccf
H^2O	3.4 lb/MMcf

INSPECTORATE

CERTIFICATE OF ANALYSIS

JOB NO.	TPA-0956542
LAB NO.	L950126-042,43,5

VESSEL	FORT PIERCE UTILITIES AUTHORITY	DATE	3-07-95
CARGO	# 6 FUEL OIL		
TERMINAL/PORT	FORT PIERCE UTILITIES, 311 NORTH INDIAN RIVER DRIVE FORT PIERCE, FL		
SAMPLE FROM	SUBMITTED		
SAMPLE SUBMITTED BY	FORT PIERCE UTILITIES AUTHORITY		
ANALYSIS PERFORMED BY	INSPECTORATE AMERICA, TAMPA		
CLIENT(S) REF.	P.O. # 29536		

TEST		RESULTS	
L950125-043	SUBMITTED SAMPLE 7 pm to 12 pm COMPOSITE — 1/25/95		
D-287	DENSITY @ 15 DEG C	0.9267	= 7.722 LBS/gal
D-4294	SULFUR, WT %	0.78	
D-240	HEAT OF COMBUSTION * 146941.93 BTU/gal.	19,029	
L950126-042	SUBMITTED SAMPLE, 12 pm to 8 am COMPOSITE — 1/26/95		
D-287	DENSITY @ A5 DEG C	0.9267	(7.72)
D-4294	SULFUR, WT %	0.77	
D-240	HEAT OF COMBUSTION *147644.64 BTU/gal.	19,120	
L950209-058			
D-287	DENSITY @ A5 DEG C - 2/9/95	0.9261	(7.717)
D-4294	SULFUR, WT %	0.78	
D-240	HEAT OF COMBUSTION * 146615.28 BTU/gal.	18,999	
		19,049	

* AS PER DAN Buck of INSPECTORATE 3/14/95

FOR INSPECTORATE: [signature]

Attachment C

DESCRIPTION OF CONTROL EQUIPMENT

ON UNITS NO. 6, 7 AND 9

BEST AVAILABLE COPY

General ELECTRIC MARK IV

Model #

Serial #

DATE INSTALLED

STEAM INJECTION

GENERAL

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

STEAM INJECTION HARDWARE

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

Devices

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

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

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

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

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

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

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

CONTROL PANEL/OPERATOR INTERFACES

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

STATEMENT OF BASIS

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

Title V Air Operation Permit Revision
FINAL Title V Permit Revision No.: 1110003-004-AV

The initial Title V air operation permit went final on December 31, 1997 and effective on January 1, 1998. This Title V air operation permit with 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.

The subject of the permit revision is to incorporate the request of Ft. Pierce Utilities Authority to eliminate No. 6 residual fuel oil, where previously permitted, and substitute the use of No. 2 fuel oil at the plant. This will result in a decrease in actual sulfur dioxide emissions when fuel oil is combusted.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. Thomas W. Richards
Director of Operations
Fort Pierce Utilities Authority
P. O. Box 3191
Fort Pierce, Florida 34948
_________________________________/

FINAL Permit No.: 1110003-004-AV
H. D. King Power Plant

Enclosed is FINAL Title V Permit Revision No.: 1110003-004-AV for the operation of the H. D. King Power Plant located at 311 North Indian River Drive, Fort Pierce, St. Lucie County, issued pursuant to Chapter 403, Florida Statutes (F.S.).

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the permitting authority in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the permitting authority.

Executed in Tallahassee, Florida.

for Scott M. Sheplak
C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 6/27/00 to the person(s) listed or as otherwise noted:

Mr. Thomas W. Richards*
Mr. George Miller, Ft. Peirce Utilities Authority
Mr. Isidore Goldman, PE, FDEP SED
Mr. Gregg Worley, USEPA, Region 4 (INTERNET E-mail Memorandum)
Ms. Elizabeth Bartlett, USEPA, Region 4 (INTERNET E-mail Memorandum)

Clerk Stamp

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

Barbara J. Boutwell 6/27/00
(Clerk) (Date)

FINAL PERMIT DETERMINATION

FINAL Title V Permit Revision No.: 1110003-004-AV
Page 1 of 1

I. Comment(s).

No comments were received from USEPA during their 45 day review period of the PROPOSED permit.

II. Conclusion.

Since there were no comments received during the USEPA 45 day review period, no changes were made to the PROPOSED Title V Permit Revision and the permitting authority hereby issues the FINAL Title V Permit Revision No.: 1110003-004-AV.

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

Title V Air Operation Permit Revision
FINAL Title V Permit Revision No.: 1110003-004-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: 850/488-1344
Fax: 850/922-6979

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

RECEIVED
JUN 30 2000
POWER GENERATION

Title V Air Operation Permit Revision
FINAL Title V Permit Revision No.: 1110003-004-AV

Table of Contents

FLORIDA GAS TRANSMISSION COMPANY

Spot Analysis of Natural Gas for Delivery in Florida

DATE: April 25, 1995
TIME: 11:48

Component Name	Mole %
Hexane	0.054
Propane	0.390
Isobutane	0.101
n-Butane	0.080
Isopentane	0.031
n-Pentane	0.018
Nitrogen	0.349
Methane	96.060
CO_2	0.746
Ethane	2.171
Totals	100.000

Dry Btu/cf @ 14.730 psia and 60°F = 1033.7
Real Relative Density = 0.5829

Total Sulfur	0.16 Gr/Ccf
Total Sulfur D/S	0.35 Gr/Ccf
H^2S	0.04 Gr/Ccf
H^2O	3.4 lb/MMcf

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3/95

INSPECTORATE

CERTIFICATE OF ANALYSIS

JOB NO.	TPA-0956542
LAB NO.	L950214-057

VESSEL	FORT PIERCE UTILITIES AUTHORITY	DATE	3-07-95
CARGO	# 2 FUEL OIL		
TERMINAL/PORT	FORT PIERCE UTILITIES, 311 NORTH INDIAN RIVER DRIVE FORT PIERCE, FL		
SAMPLE FROM	SUBMITTED		
SAMPLE SUBMITTED BY	FORT PIERCE UTILITIES AUTHORITY		
ANALYSIS PERFORMED BY	INSPECTORATE AMERICA, TAMPA		
CLIENT(S) REF.	P.O. # 43810		

TEST		RESULTS
D-287	API GRAVITY @ 60 DEG F	32.4
D-93	FLASH POINT, PMCC, DEG F	182
D-97	POUR POINT, DEG C	-23
D-4294	SULFUR, WT %	0.41
D-95	WATER BY DISTILLATION	<0.025
D-189	CARBON RESIDUE, WT.%, 10% BOTTOMS	0.07
D-482	ASH, WT %	<0.01
AAS	VANADIUM, PPM	<0.3
AAS	SODIUM, PPM	<0.2
AAS	POTASSIUM, PPM	<0.3
AAS	CALCIUM, PPM	<0.3
AAS	LEAD, PPM	<0.3
D-3228	NITROGEN, PPM	145
D-240	HEAT OF COMBUSTION, GROSS BTU/LB	19,524
D-976	CETANE INDEX	45.7
D-2274	PARTICULATES, MG/LITER	21
D-86	DISTILLATION, % RECOVERED, DEG F	-
	IBP/5	408/444
	10/20	464/486
	30/40	502/518
	50/60	536/550
	70/80	566/586
	90/EP	610/660
	REC/RES/LOSS	98.0/1.9/0.1
	BACTERIAL CONTAMINATION	SLIGHT
PE-240-C	HYDROGEN WT. %	13.38 %

FOR INSPECTORATE: [signature]

O-COA
REV 12 - 2/94

HEAT of Combustion BTU/GAL = 140358.03 BTU/GAL

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INSPECTORATE

CERTIFICATE OF ANALYSIS

JOB NO.	TPA-0956542
LAB NO.	L950126-042,43,5

VESSEL	FORT PIERCE UTILITIES AUTHORITY	DATE	3-07-95
CARGO	# 6 FUEL OIL		
TERMINAL/PORT	FORT PIERCE UTILITIES, 311 NORTH INDIAN RIVER DRIVE FORT PIERCE, FL		
SAMPLE FROM	SUBMITTED		
SAMPLE SUBMITTED BY	FORT PIERCE UTILITIES AUTHORITY		
ANALYSIS PERFORMED BY	INSPECTORATE AMERICA, TAMPA		
CLIENT(S) REF.	P.O. # 29536		

TEST		RESULTS	
L950125-043	SUBMITTED SAMPLE 7 pm to 12 pm COMPOSITE — 1/25/95		
D-287	DENSITY @ 15 DEG C	0.9267	= 7.722 LBS/gal
D-4294	SULFUR, WT %	0.78	
D-240	HEAT OF COMBUSTION * 146941.93 btu/gal.	19,029	
L950126-042	SUBMITTED SAMPLE, 12 pm to 8 am COMPOSITE — 1/26/95		
D-287	DENSITY @ A5 DEG C	0.9267	(7.72)
D-4294	SULFUR, WT %	0.77	
D-240	HEAT OF CUMBUSTION *147644.64 btu/gal.	19,120	
L950209-058			
D-287	DENSITY @ A5 DEG C - 2/9/95	0.9261	(7.717)
D-4294	SULFUR, WT %	0.78	
D-240	HEAT OF COMBUSTION * 146615.28 btu/gal.	18,999	
		19,049	

* AS PER DAN Buck of INSPECTORATE 3/14/95

FOR INSPECTORATE: [signature]

Q-COA
REV #2 - 7/94

Attachment C

DESCRIPTION OF CONTROL EQUIPMENT

ON UNITS NO. 6, 7 AND 9

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General ELECTRIC MARKIV

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ATE INSTALLED

STEAM INJECTION

GENERAL

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

STEAM INJECTION HARDWARE

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

Devices

1. A metering tube and orifice are the primary devices for measurement of steam flow
2. Two differential transmitters (96SJ-1, -2) measure pressure drop across the orifice. The two transmitters operate in a split-range mode, where one transmitter is calibrated to monitor the lower range of flow and the other, the higher range. Thus, the total flow range measurement accuracy is improved compared to a single transmitter arrangement.
3. A pressure transmitter (96PJ-1) measures steam pressure for calculation of steam flow and indication of steam condition.
4. Three thermocouples (ST-SJ-1, -2, -3) measure steam temperature for calculation of steam flow and indication of steam condition.
5. A pneumatically operated stop valve (controlled by trip solenoid 20SJ-1) opens to permit steam injection flow and closes to shut off flow when the system is not operating or when the system is tripped. A limit switch (33SJ-1) indicates valve-closed position.
6. Two pneumatically operated valves (controlled by solenoid valves 20BS-1, -2) provide steam-line condensate drain and warm-up prior to injection. Limit switches indicate valve position.
7. A steam control valve regulates the flow of steam to the gas turbine. This valve is driven by an electromechanical motor actuator which receives direction (open or close) and run signals from the gas turbine control system. The control valve has a limit switch which indicates valve fully closed position.

CONTROL PANEL/OPERATOR INTERFACES

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

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

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

STEAM FLOW CONTROL

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

As shown in Figure SIR4000-2, steam flow is initiated when fuel flow to the turbine reaches the value specified by constant WQK( )_E. At this point, the steam injection flow setpoint is released from 0. The setpoint assumes a value in accordance with the measured fuel flow, ambient temperature, and specific humidity. The control valve is allowed to ramp open until steam flow equals the setpoint. The ramp consists of a series of small steps. The control valve motor is turned on (in the open direction) for a fixed length of time and then turned off for another fixed length of time. The on time is set by timer L2WQOF1 and the off time by timer L2WQON. The ramp should be adjusted so the control valve opens as quickly as possible without upsetting the steam supply conditions.

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

PROTECTIVE FEATURES

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

Steam Supply Condition Trouble

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

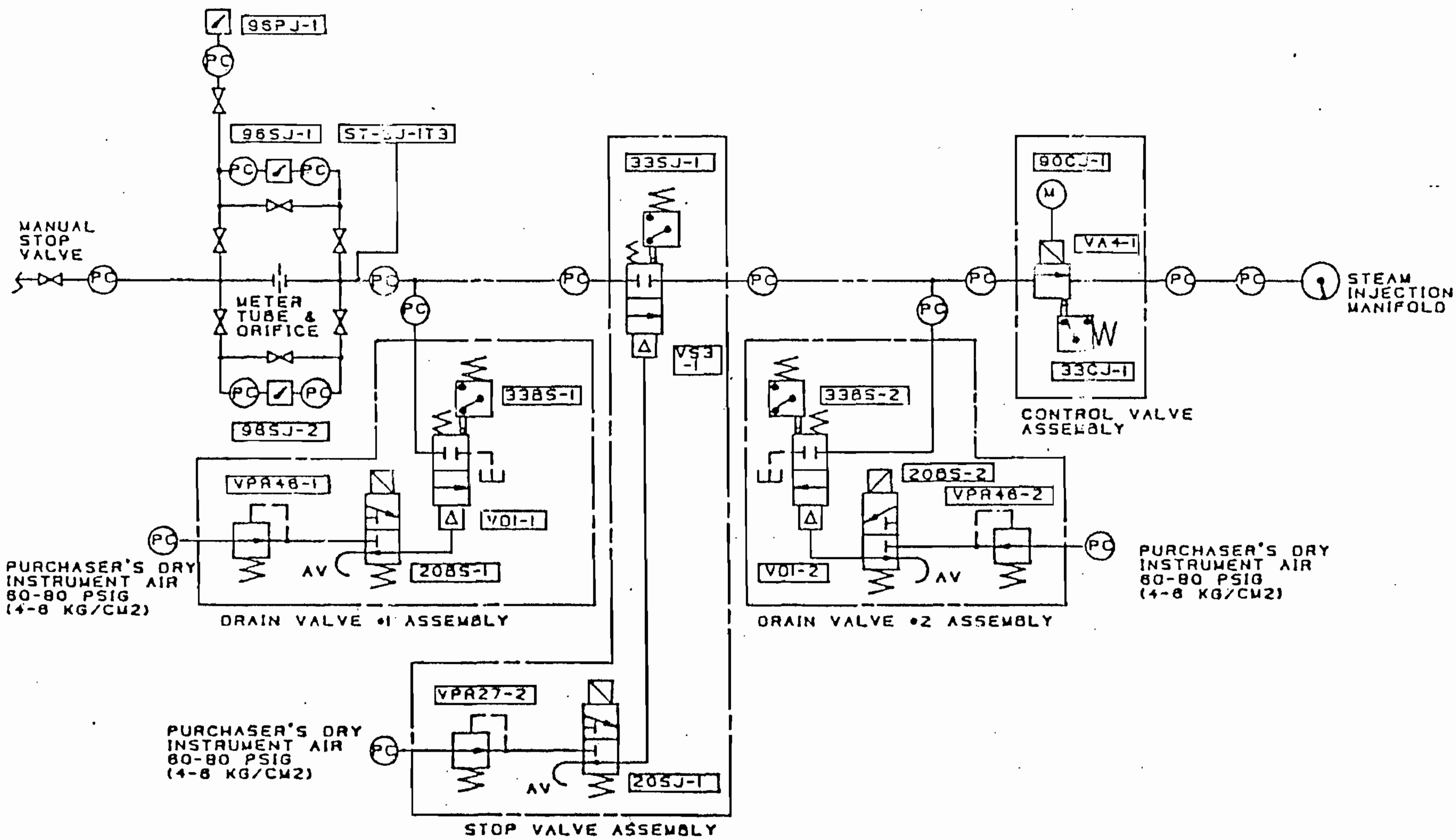

FIGURE SIR4000-1
(788)

STEAM SUPPLY CONDITION
ALARM & SHUTDOWN

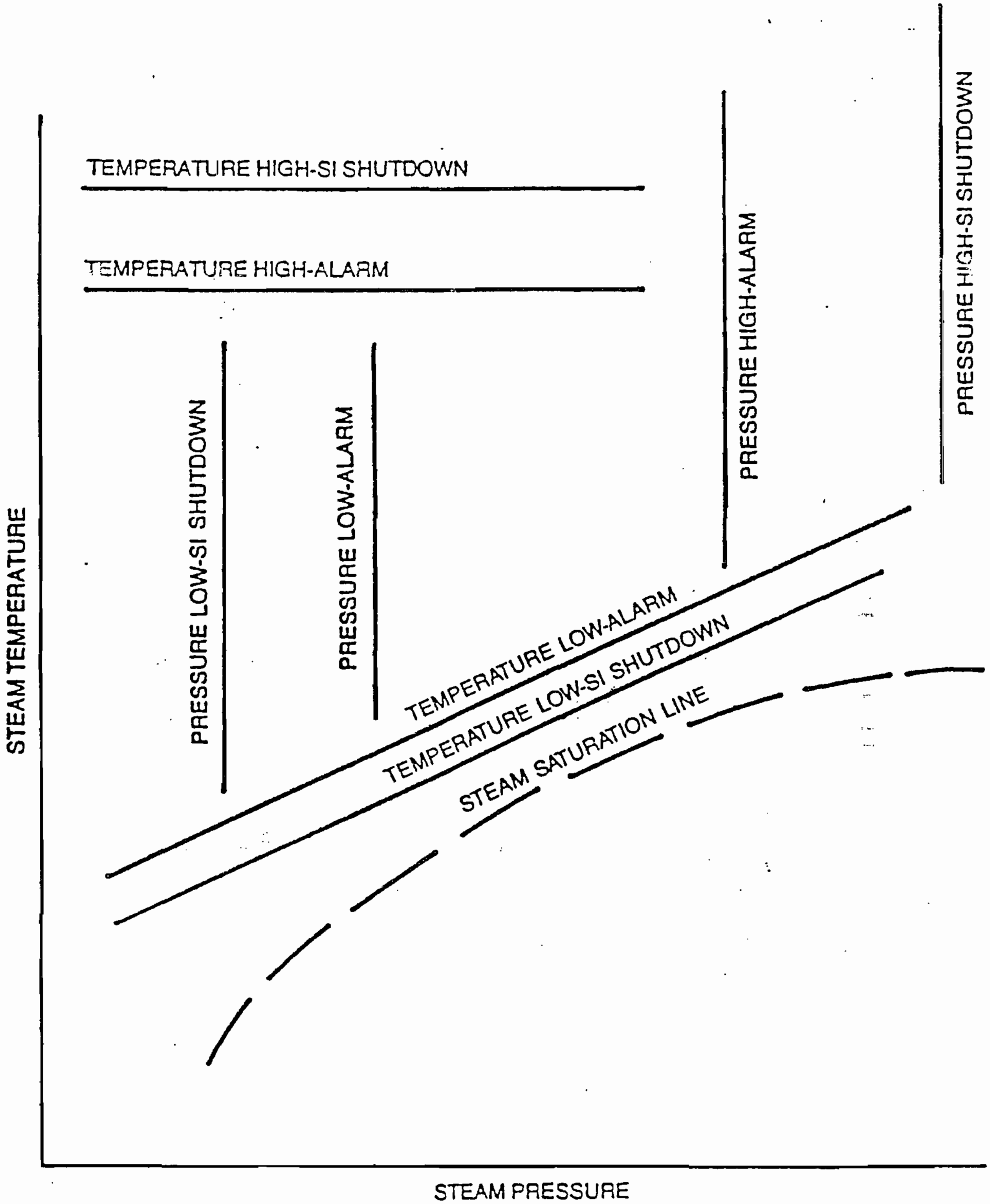

FIGURE SIR4000-3
(788)

GENERAL

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

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

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

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

FUNCTIONAL DESCRIPTION

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

SYSTEM REQUIREMENTS

STEAM SUPPLY

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

INSTRUMENT AIR

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

OPERATION

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

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

PRE-OPERATION CHECKS

Prior to operation, check for the following conditions:

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

START UP

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

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

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

MAINTENANCE

PERIODIC MAINTENANCE

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

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

TROUBLE SHOOTING

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

a. Steam supply exhausted.

b. Insufficient supply pressure.

c. Control valve closed.

d. Stop valve closed.

The following should be checked:

a. Adequate steam supply.

b. Check steam supply system.

c. Check control valve actuator and drain valve operation.

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

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

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

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

STEAM INJECTION SYSTEM

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

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

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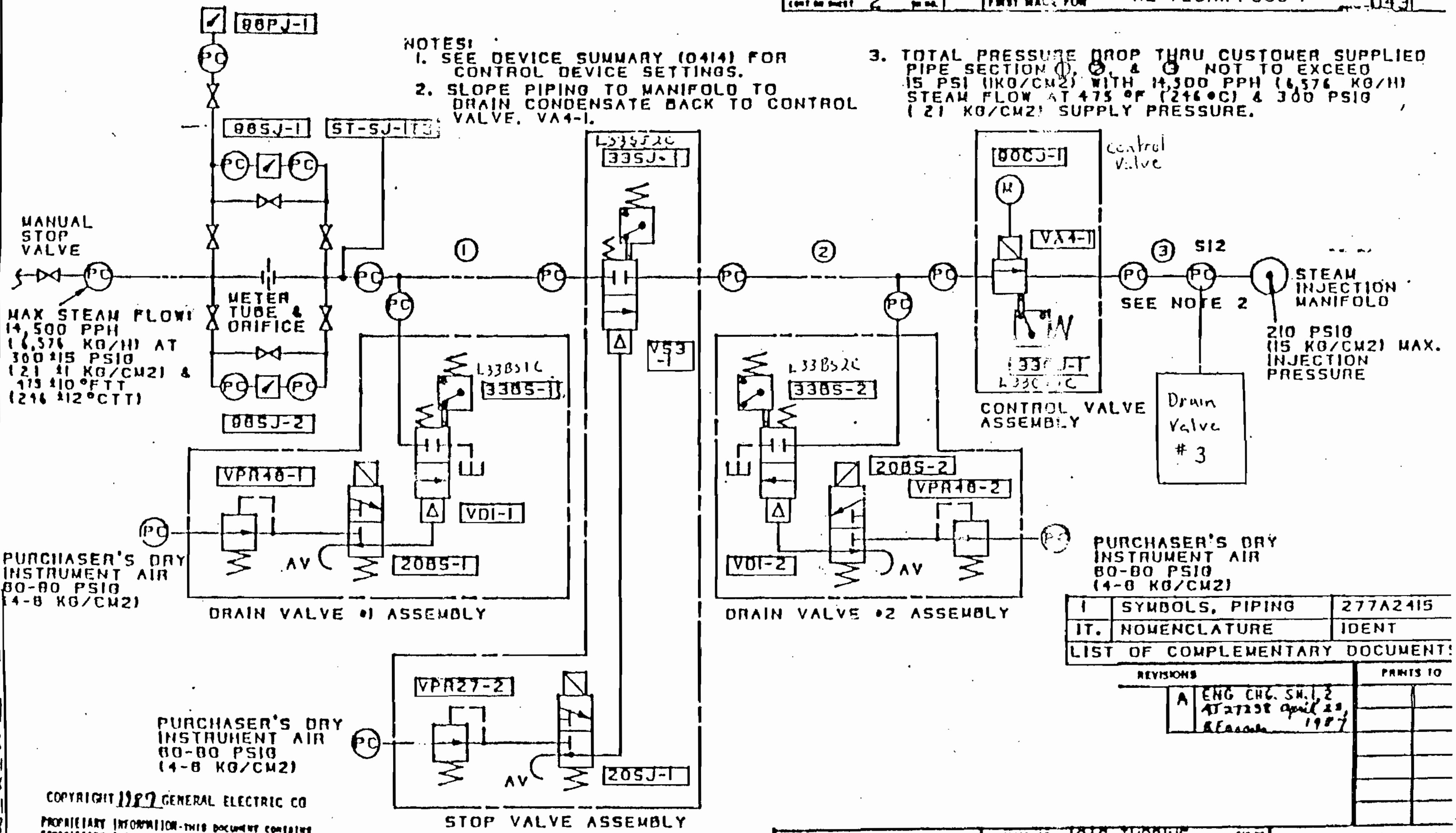
NOX

GENERAL ELECTRIC

247B5083	CONT ON SHEET 2 · SH NO. 1
TITLE	DIAGRAM, SCHEM PP-ST INJECTION
FIRST MADE FOR	ML-7L5AIPP388-1 · 0431

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



1	SYMBOLS, PIPING	277A2415
IT.	NOMENCLATURE	IDENT
LIST OF COMPLEMENTARY DOCUMENTS		

REVISIONS — A: ENG CHG. SH. 1, 2 AT27238 April 23, 1987

PRINTS TO

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PROPRIETARY INFORMATION - THIS DOCUMENT CONTAINS PROPRIETARY INFORMATION OF THE GENERAL ELECTRIC COMPANY AND MAY NOT BE USED OR DISCLOSED TO OTHERS, EXCEPT WITH THE WRITTEN PERMISSION OF GAS TURBINE DIVISION, GENERAL ELECTRIC COMPANY.

MADE BY 3/27/87 · ISSUED March 31, 1987

GAS TURBINE · SCHENECTADY

247B5083 · CONT ON SHEET 2 · SH NO. 1 · REV. A

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STEAM INJECTION

GENERAL

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

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

STEAM FLOW CONTROL

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As shown in Figure SIR4000-2, steam flow is initiated when fuel flow to the turbine reaches the value specified by constant WQK( )E. At this point, the steam injection flow setpoint is released from 0. The setpoint assumes a value in accordance with the measured fuel flow, ambient temperature, and specific humidity. The control valve is allowed to ramp open until steam flow equals the setpoint. The ramp consists of a series of small steps. The control valve motor is turned on (in the open direction) for a fixed length of time and then turned off for another fixed length of time. The on time is set by timer L2WQOF1 and the off time by timer L2WQON. The ramp should be adjusted so the control valve opens as quickly as possible without upsetting the steam supply conditions.

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Steam Supply Condition Trouble

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

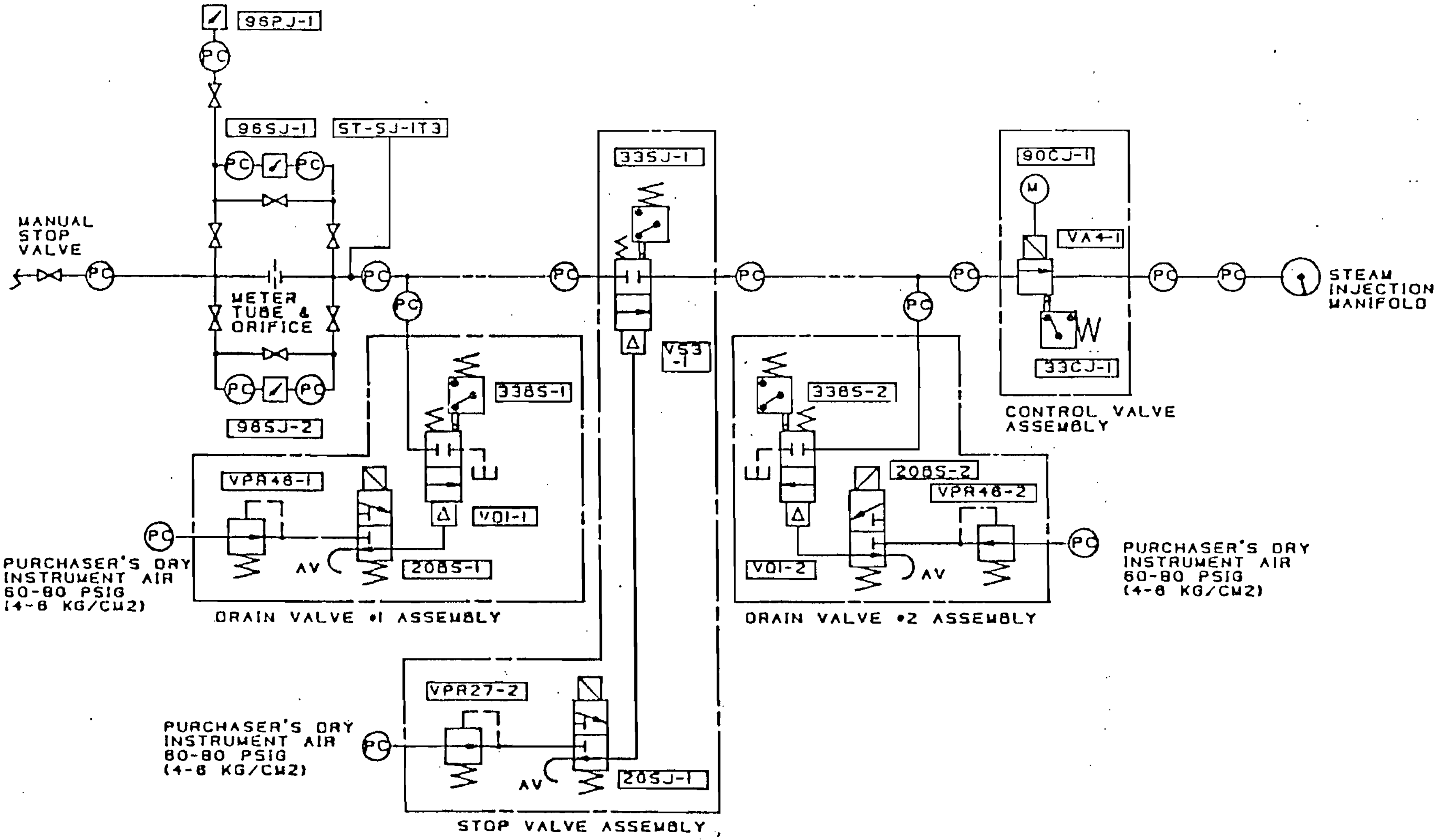

FIGURE SIR4000-1
(788)

STEAM SUPPLY CONDITION
ALARM & SHUTDOWN

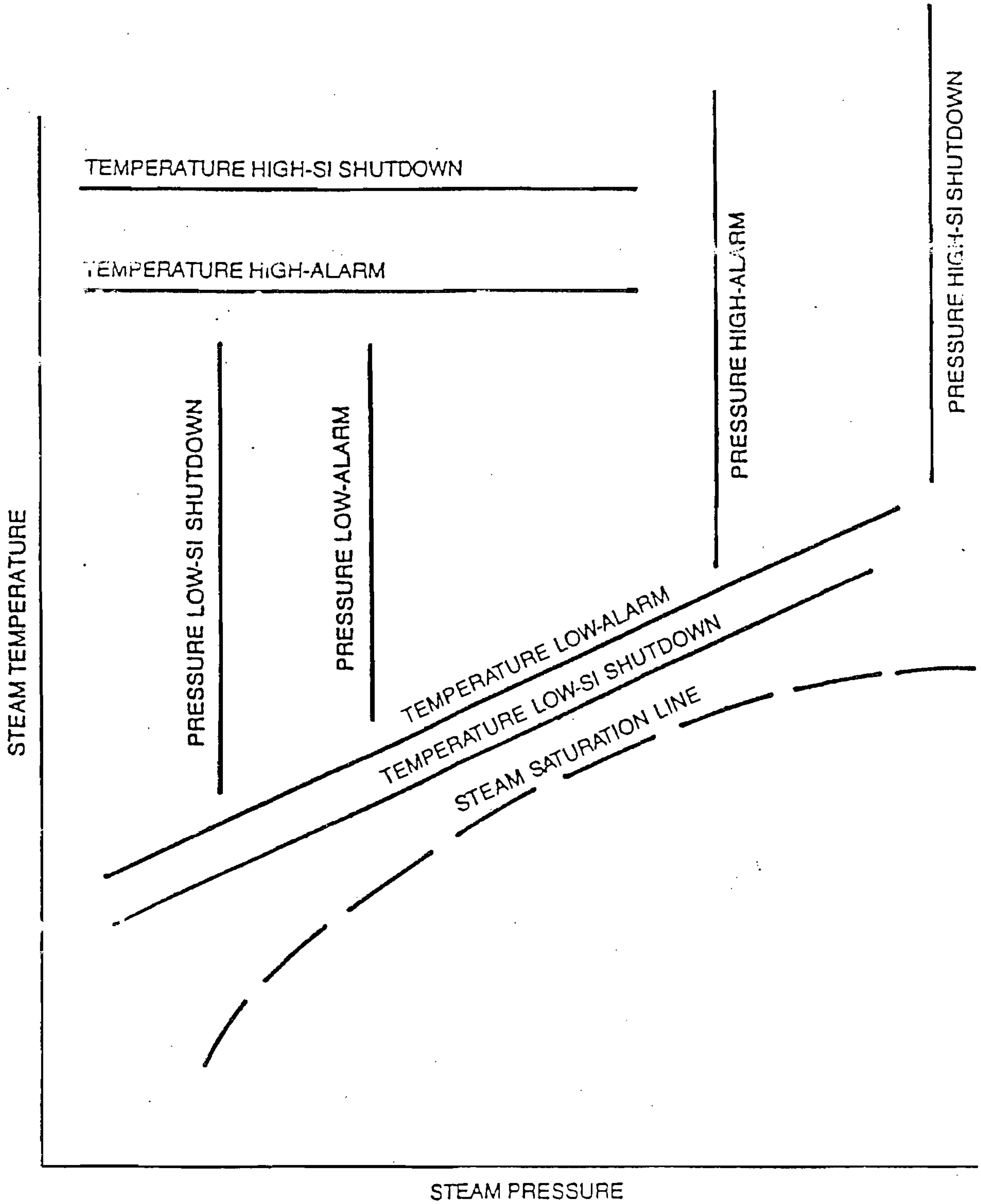

FIGURE SIR4000-3
(788)

STEAM INJECTION SYSTEM

GENERAL

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

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

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

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

FUNCTIONAL DESCRIPTION

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

SYSTEM REQUIREMENTS

STEAM SUPPLY

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

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

TROUBLE SHOOTING

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

a. Steam supply exhausted.

b. Insufficient supply pressure.

c. Control valve closed.

d. Stop valve closed.

The following should be checked:

a. Adequate steam supply.

b. Check steam supply system.

c. Check control valve actuator and drain valve operation.

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

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

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

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

STEAM INJECTION SYSTEM

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

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

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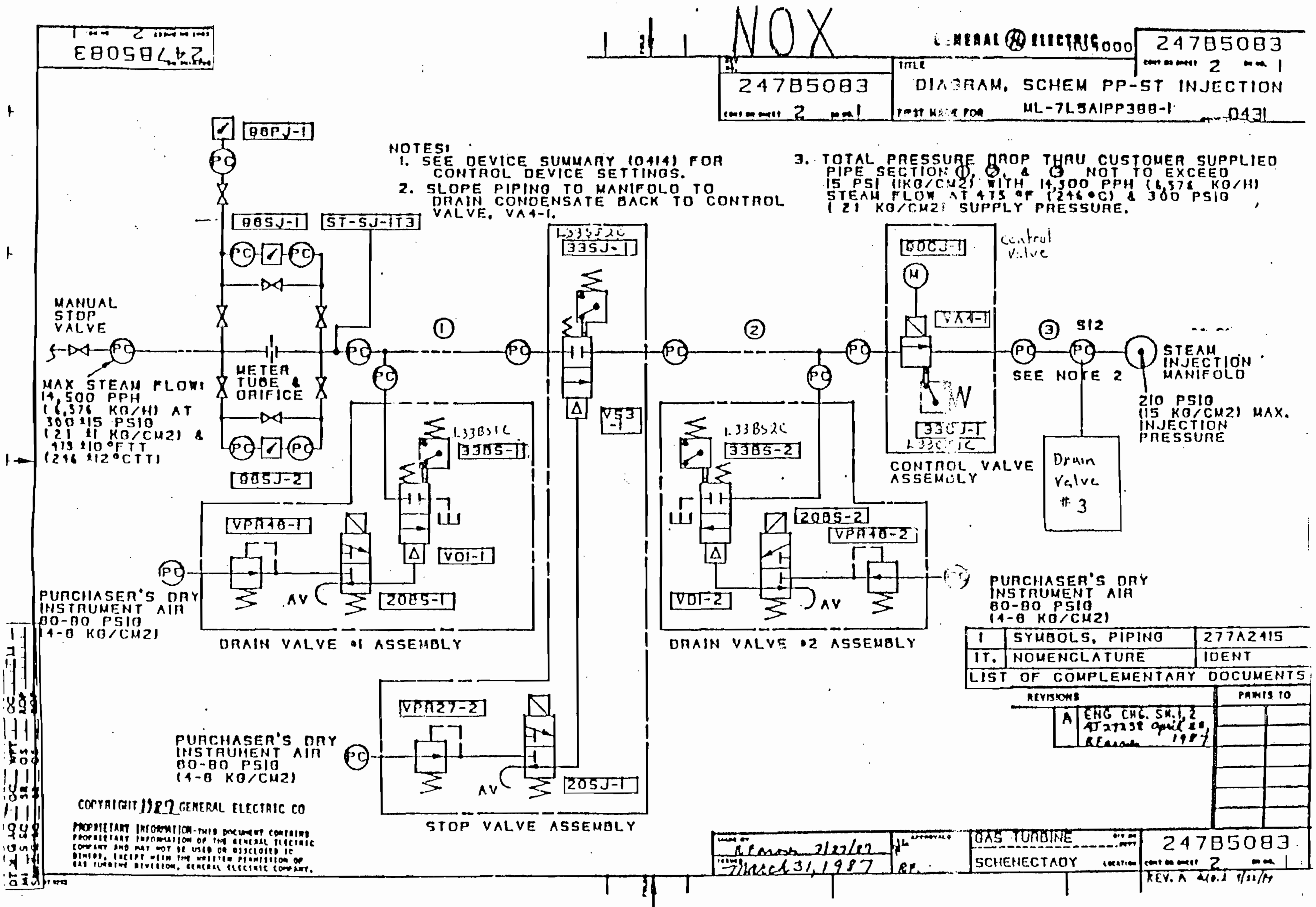


CYCLONES

PRAT-DANIEL CORPORATION

POWER PLANT EQUIPMENT

Executive Offices and Plant
South Norwalk, Conn.

Fans, Stacks
Dust Collectors
Air Heaters
Thermobloc
Industrial Heaters

Project & Sales Engineers
THE THERMIX CORPORATION
Greenwich, Connecticut

JOB SUMMARY

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

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

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

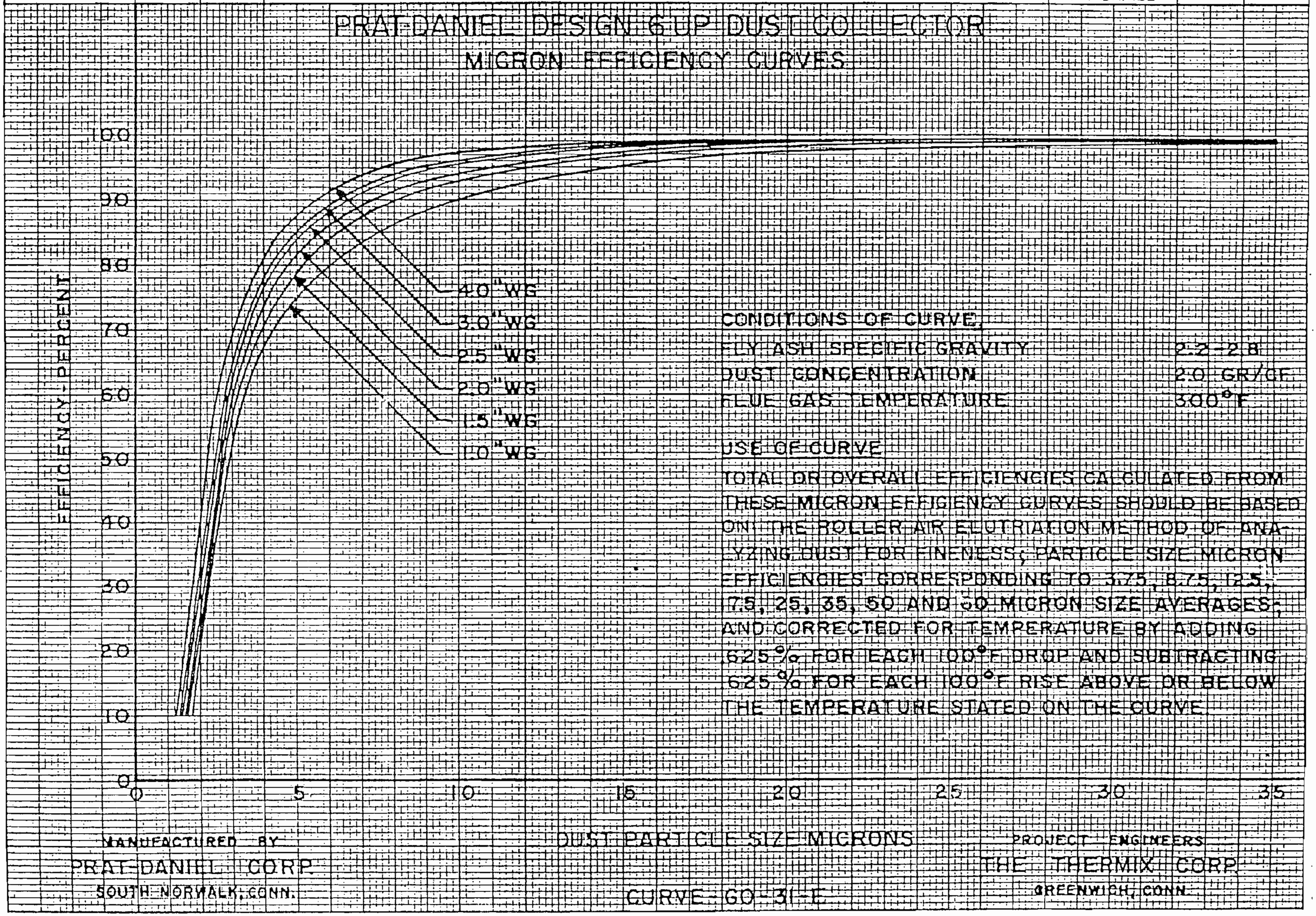
Lbs. gas per hour	242,000
Temperature deg. F.	350
Collector resistance, "w.g.	2.5

Collection efficiency based on Curve GO-31-E.

MM:MMT
5/15/56

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

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



FORM: PDC 4513

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UNIT #7
CYCLONES

JOB SUMMARY

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

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

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

Lbs. Gas per Hour	248,000	269,000
Temperature Deg. F.	311	311
CFM at Pressure	77,100	83,900
Collector Resistance "W.G.	2.50	2.96
Collection Efficience, %	91	

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

DUST ANALYSIS
ELUTRIATION

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

AT/cf
9/26/61

Attachment D

DESCRIPTION OF STACK SAMPLING FACILITIES

FOR UNITS 7, 8 AND 9

Unit 9

4.2 Sampling Locations

Locations of the sample ports and stack dimensions are shown in Figure 1. sampling was performed through seven ports located on one side of the rectangular stack. Forty two sample points were selected for the preliminary oxygen traverse in accordance with EPA Method 20 and EPA Method 1 - Sample and Velocity Traverses for Stationary Sources, 40 CFR 60, Appendix A. Of these forty two points, twelve points exhibiting the lowest oxygen concentartions wee utilized for the sulfur dioxide sampling.

Carbon monoxide, nitrogen oxides, and oxygen sampling were performed from the same sampling ports as the sulfur dioxide sampling.

4.3 Sampling Trains

The sulfur dioxide sampling train consisted of a Nutech Corporation 10 foot probe utilizing a stainless steel nozzle, a heated glass liner, a heated glass fiber filter and four impingers arranged as shown in Figure 2. The first impinger was charged with 100 milliliters of 80% iscpropanol, the second and third impingers were each charged with 100 milliliters of 3% hydrogen peroxide and the fourth impinger was charged with indicating silica gel desiccant. The impingers were cooled in an ice and water bath during sampling. A Nutech Corporation control console was used to monitor the gas flow rates and stack conditions during sampling.

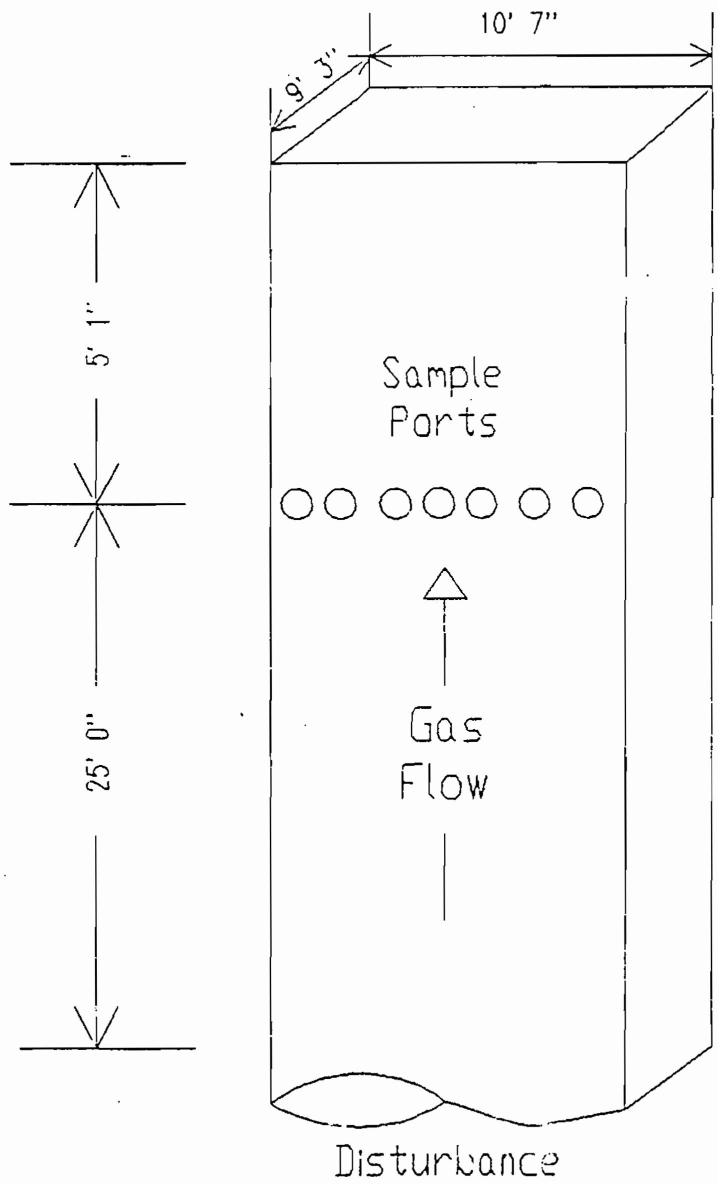
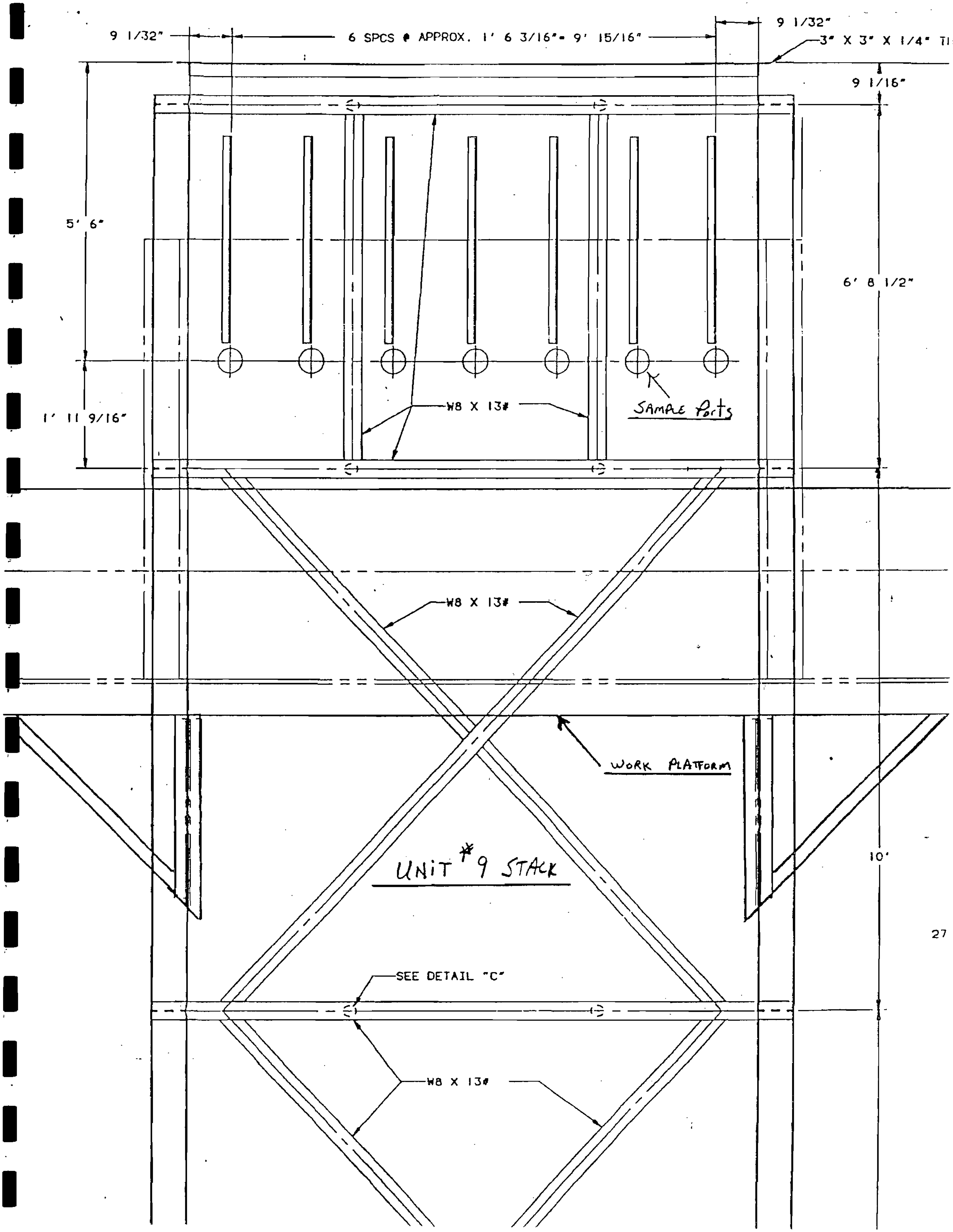


Figure 1. Stack Dimensions and sample port locations, Fort Pierce Utilities Authority, H.D. King Electric Generating Plant, Unit No.9. Fort Pierce, Florida.



9 1/32"
6 SPCS @ APPROX. 1' 6 3/16" = 9' 15/16"
9 1/32"
3" X 3" X 1/4" T
9 1/16"
5' 6"
6' 8 1/2"
1' 11 9/16"
W8 X 13#
SAMPLE Ports
W8 X 13#
WORK PLATFORM
UNIT #9 STACK
10'
SEE DETAIL "C"
W8 X 13#

Appendix A. Nitrogen oxides emissions sampling was conducted in accordance with EPA Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure), 40 CFR 60, Appendix A. Sulfur dioxide emissions sampling was conducted in accordance with EPA Method 6 - Determination of Sulfur Dioxide Emissions from Stationary Sources, 40 CFR 60, Appendix A. Volatile organic compounds emissions sampling was conducted in accordance with EPA Method 25A - Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer, 40 CFR 60, Appendix A. Visible emissions were determined in accordance with EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources, 40 CFR 60, Appendix A.

Unit 7

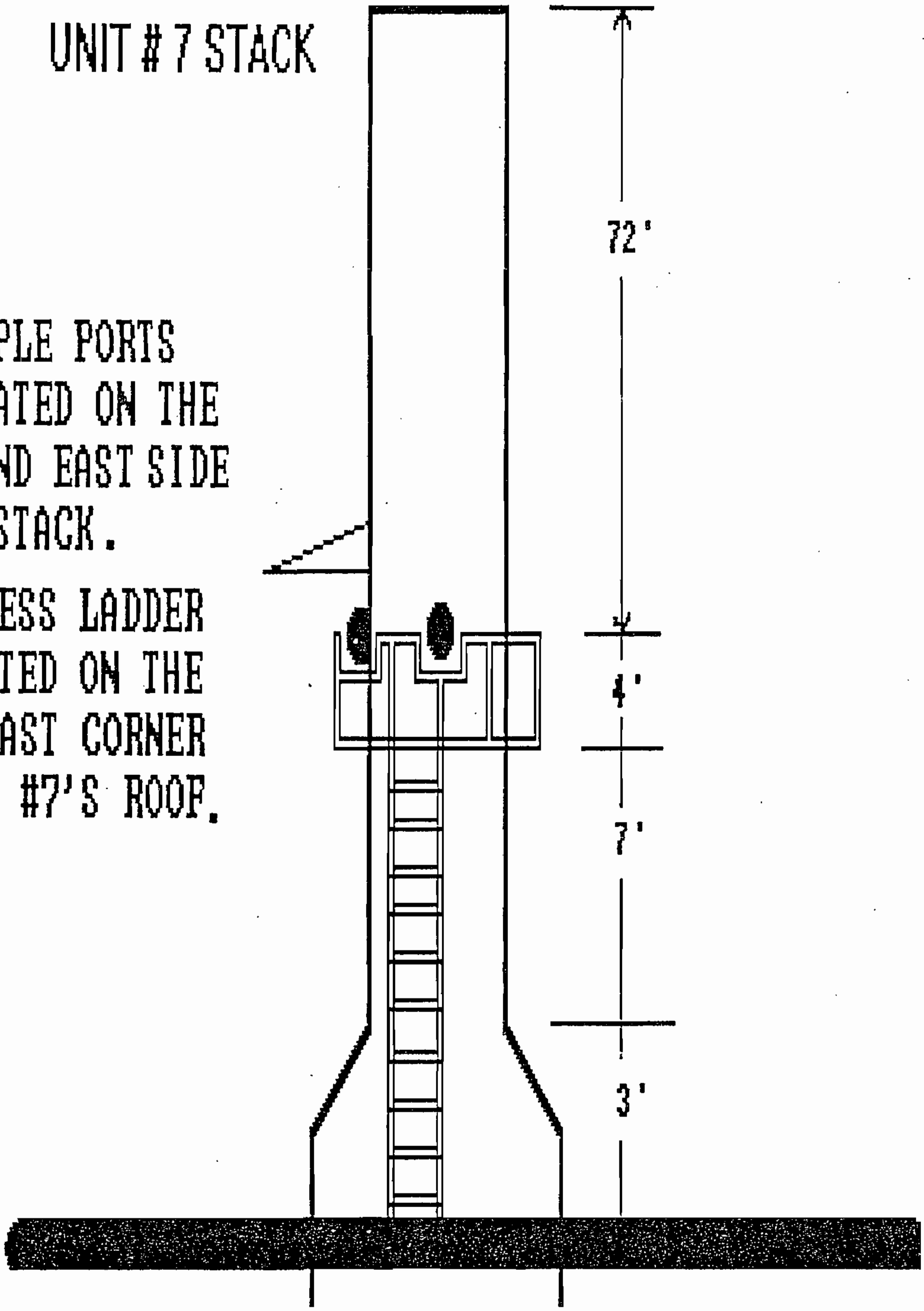
4.2 Sampling Locations

Locations of the sample ports and stack dimensions are shown in Figure 1. Particulate and sulfur dioxide sampling was performed by conducting horizontal traverses through each of two ports located on the stack at a ninety degree angle from one another. Twenty four sample points were chosen in accordance with EPA Method 1 - Sample and Velocity Traverses for Stationary Sources, 40 CFR 60, Appendix A. Carbon monoxide, nitrogen oxides, volatile organic compounds, and oxygen sampling were performed from the same sampling ports as the particulate sampling.

UNIT # 7 STACK

THE SAMPLE PORTS ARE LOCATED ON THE SOUTH AND EAST SIDE OF THE STACK.

THE ACCESS LADDER IS LOCATED ON THE SOUTH EAST CORNER OF UNIT #7'S ROOF.



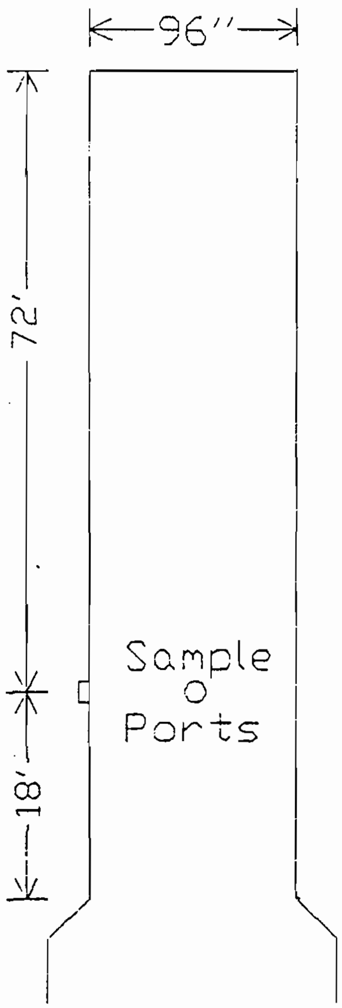


Figure 1. Stack Dimensions and sample port locations, Fort Pierce Utilities Authority, H.D. King Electric Generating Plant, Unit 7. Fort Pierce, Florida.

Appendix A. Nitrogen oxides emissions sampling was conducted in accordance with EPA Method 7E - Determination of Nitrogen Oxides Emissions from Stationary Sources (Instrumental Analyzer Procedure), 40 CFR 60, Appendix A. Sulfur dioxide emissions sampling was conducted in accordance with EPA Method 6 - Determination of Sulfur Dioxide Emissions from Stationary Sources, 40 CFR 60, Appendix A. Volatile organic compounds emissions sampling was conducted in accordance with EPA Method 25A - Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer, 40 CFR 60, Appendix A. Visible emissions were determined in accordance with EPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources, 40 CFR 60, Appendix A.

Unit 8

4.2 Sampling Locations

Locations of the sample ports and stack dimensions are shown in Figure 1. Particulate and sulfur dioxide sampling was performed by conducting horizontal traverses through each of two ports located on the stack at a ninety degree angle from one another. Twenty four sample points were chosen in accordance with EPA Method 1 - Sample and Velocity Traverses for Stationary Sources, 40 CFR 60, Appendix A. Carbon monoxide, nitrogen oxides, volatile organic compounds, and oxygen sampling were performed from the same sampling ports as the particulate sampling.

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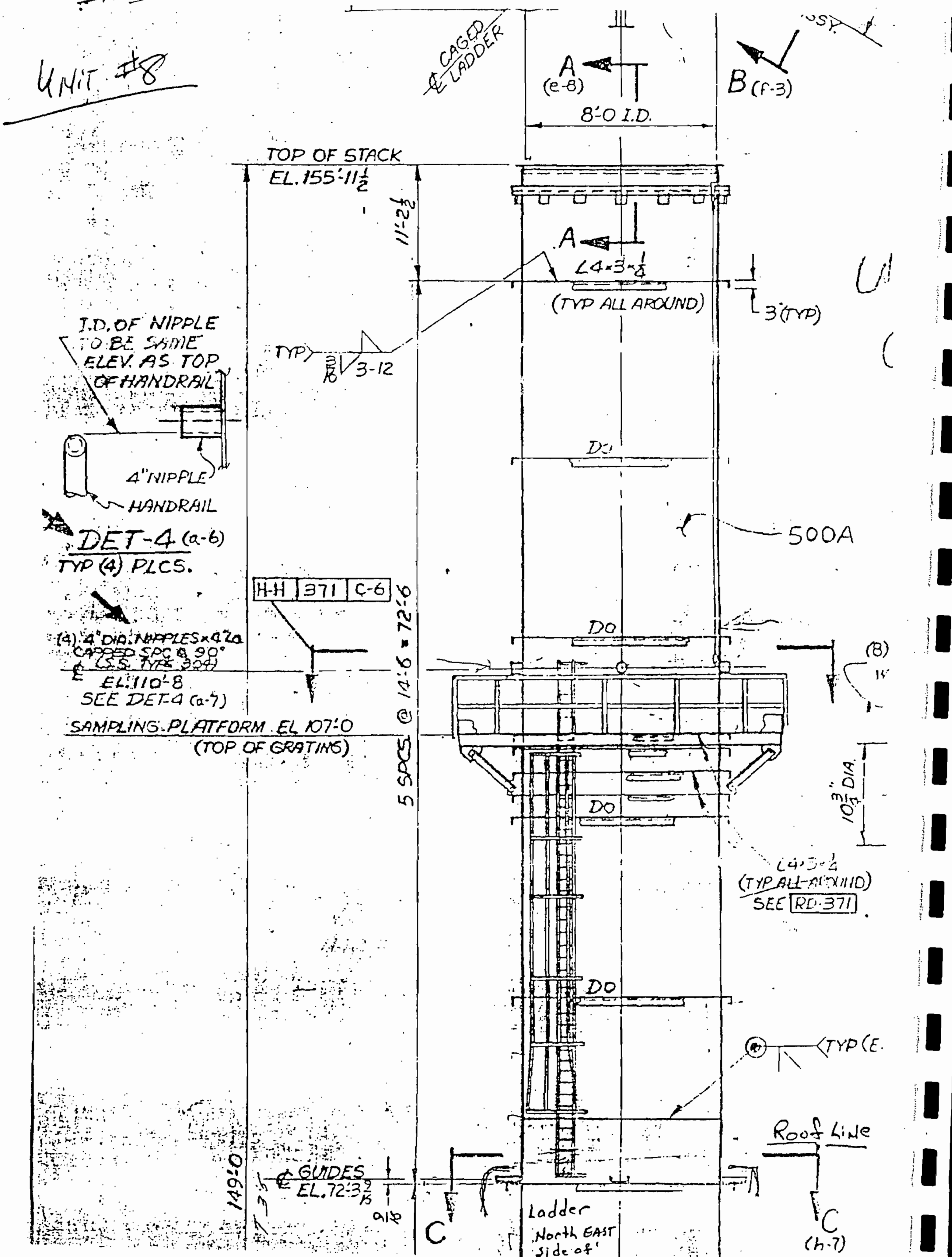

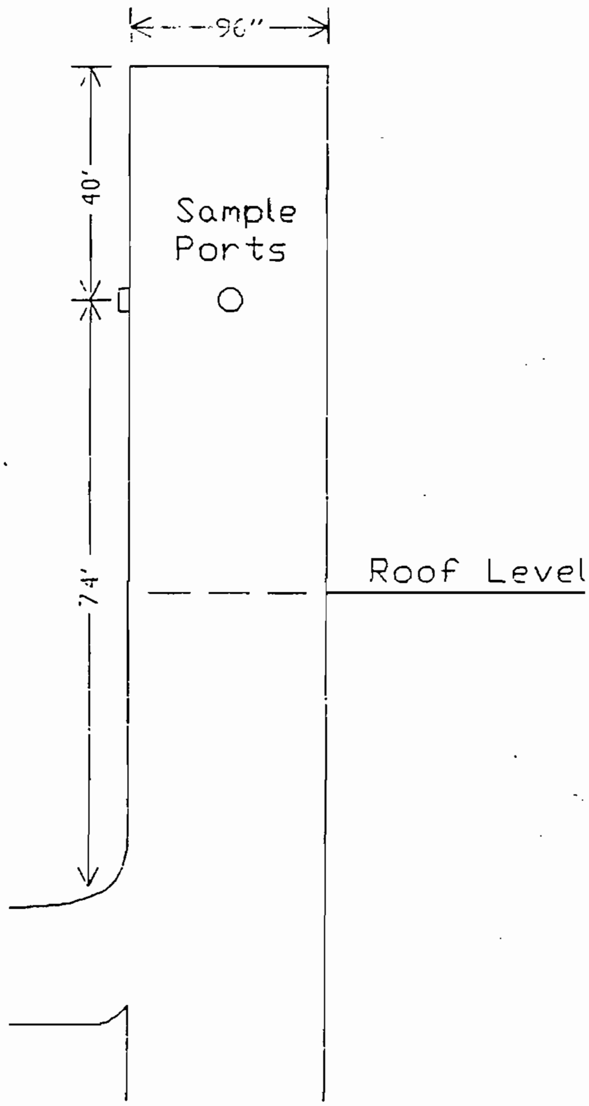

Figure 1. Stack Dimensions and sample port locations, Fort Pierce Utilities Authority, H.D. King Electric Generating Plant, Unit 8. Fort Pierce, Florida.

Attachment E

PROCEDURES FOR

STARTUP AND SHUTDOWN

DIESEL STARTUP PROCEDURE

1 Place mode selector switch in 'peak inc.'

2 Turn 'on' synchroscope

3 Place meter selection in '2'

4 Place bus vm-fm-gen in '2-3'

5 Turn mode selector switch to 'idle'

6 Turn diesel start switch to 'start' (spring loaded no need to hold)

7 Unit will start, watch smoke coming from stack. What colour is it?

8 Turn mode selector switch to 'run'

9 Turn mode selector switch to 'excite'

10 Lower governor control till 60 hz, unit is ready for synchronizing.

11 When synchroscope is at 12:00/noon, 'close' generator breaker

12 Raise governor control this puts load on unit

13 Turn mode selector switch to 'auto'

14 Turn 'off' : bus-vm-gen, meter selection and synchroscope

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#9 AND #5 START-UP PROCEDURE

PURPOSE

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

SCOPE

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

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

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

POLICY

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

GENERAL

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

RESPONSIBILITY

Watch Engineer

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

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

RESPONSIBILITY (continued)

Control/Boiler and Auxiliary Operators

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

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

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

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#9 AND #5 START-UP LIST

Date ________

PROCEDURES

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

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

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#9 AND #5 START-UP LIST

Date __________

1. IF UNIT HAS BEEN OFF 72 HOURS OR LONGER, MEGGER ALL 2400V MOTORS. ☐
2. MAKE SURE AUX. OIL PUMP AND HEATER ON #5 IS ON. ☐
3. CHECK TO SEE IF ALL BREAKERS ON #5 ARE RACKED IN. ☐
4. MAKE SURE GENERATOR HEATERS ARE ON. ☐
5. OPEN ALL DRAINS AND VENTS ON #9 BOILER. ☐
6. MAKE SURE ECONOMIZER VENT IS OPEN (1 TURN IN OPERATION.) ☐
7. OPEN MAIN STEAM STOP VALVE. ☐
8. OPEN VALVES FOR PEGGING STEAM TO WARM UP DEAERATER. ☐
9. MAKE SURE FEED WATER STOP VALVE IS OPEN. ☐
10. YOU SHOULD HAVE 2 TO 3 BUBBLES IN #9 BOILER. ☐
11. TURN ON COOLING WATER TO FLASH TANK. ☐
12. SET #9 LOAD AT APPROX. 1 TO 3 MW. ☐
13. OPEN STACK DAMPER (5 TO 20%) DEPENDING ON G.T. LOAD. ☐

    NOTE: DO NOT OPEN DAMPER MORE THAN 25% UNTIL YOU ARE READY TO COME ON-LINE WITH UNIT. BEFORE OPENING DAMPER COMPLETELY, #9 MUST BE BELOW 1 MW OR DAMAGE TO DAMPER CABLES MAY OCCUR.

14. OPEN MAIN STEAM - BELLY - BEFORE AND AFTER DRAINS ON #5. ☐
15. CHECK DA AND HOT WELL WATER LEVELS. ☐
16. LINE UP OLD SIDE MAKE-UP PUMP TO HOT WELL (OR DA.) ☐
17. CLOSE CONDENSATE INLET VALVE TO STAGE HEATER. ☐
18. OPEN BYPASS AROUND FLOAT ON CONDENSATE RECIRC LINE TO HOT WELL. ☐
19. MAKE SURE BOILER FEED PUMPS ARE READY FOR SERVICE. ☐
20. CHECK SEAL WATER TO CIRC PUMPS - PULL VACUUM ON CIRC PUMPS AND START. ☐

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#9 AND #5 START-UP LIST

Date ________

21. AT 250 PSI OF STEAM PRESSURE - START CONDENSATE PUMP - TURN OFF LUBE OIL HEATER.

    NOTE: STEAM TEMPERATURE SHOULD BE 500 DEG. F - (100 DEG. SUPERHEAT).

22. PUT APPROX. 1/2 LB. AIR PRESSURE ON GOVERNOR HOUSING SEAL.

23. CLOSE VACUUM BREAKER ON CONDENSER.

24. TURN ON GLAND WATER SUPPLY TO SEALS.

25. PUT 250 PSI STEAM STATION, AIR EJECTOR AND HOG IN SERVICE.

26. MAKE SURE STEAM DRIVEN OIL PUMP IS IN WORKING ORDER.

27. CUT MAIN STEAM DRAIN BACK TO APPROX. 1 TURN.

28. WHEN VACUUM IS UP TO APPROX. 18 INCHES Hg - RESET OIL TRIP - LATCH UP GOVERNOR.

29. ROLL AT 500 RPM - LISTEN FOR RUBS - FEEL FOR VIBRATION.

30. CLOSE BELLY AND AFTER SEAT DRAINS.

31. IF #5 IS SMOOTH - ROLL FOR A MINIMUM OF 10 MIN. - THEN GO TO 1000 RPM.

32. ROLL AT 1000 RPM FOR 20 MIN. - THEN GO TO 2200 RPM.

33. ROLL AT 2200 RPM FOR 20 MIN. - THEN GO TO 3000 RPM.

34. AT 3000 RPM - GOVERNOR TAKES OVER - WHEN GOVERNOR HAS CONTROL, OPEN THROTTLE VALVE COMPLETELY - ROLL FOR 5 MIN.

    NOTE: ALL ROLL TIMES ARE APPROX. AND SUBJECT TO CHANGE AS VIBRATION LEVELS AND CONDITIONS WARRANT.

35. GO TO SPEED SET POINT ON TRI-SEN BY PRESSING "05". RAISE SPEED ON TURBINE WITH TRI-SEN IN CONTROL ROOM USING "UP" ARROW. WHEN SPEED REACHES 3500 RPM, THE TRI-SEN WILL TAKE UNIT SPEED TO 3600 RPM AUTOMATICALLY. USE "UP" ARROW AGAIN TO BRING SPEED TO 3604 RPM.

36. WHEN TURBINE SPEED IS AT 3604 RPM - CLOSE FIELD BREAKER.

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#9 AND #5 START-UP LIST

Date __________

37. TURN ON SYNC SCOPE.

38. RAISE GEN. VOLTAGE (RUNNING) TO MATCH INCOMING VOLTAGE.

39. BOILER PRESSURE NEEDS TO BE 370 PSI MINIMUM - (STAYING THE SAME, OR INCREASING SLIGHTLY.) IF THIS CAN BE DONE WITH #9 UNIT AT 1 MW OR LESS, AND WITH THE DAMPER LESS THAN 25% OPEN, THEN SYNCHRONIZE AND CLOSE GENERATOR BREAKER, PUSH "F1" TO LOCK IN PRESSURE (CASCADE MODE), THEN OPEN DAMPER TO FULL OPEN POSITION. RAISE LOAD ON #9 UNIT SLOWLY TO LOAD UP BOTH UNITS.

IF PRESSURE CANNOT BE MAINTAINED, THEN LOWER #9 UNIT TO SLIGHTLY LESS THAN 1 MW AND OPEN CONTROL DAMPER TO FULL OPEN POSITION. RE-STABILIZE PRESSURE, INCREASING SLIGHTLY, THEN SYNCHRONIZE AND CLOSE GENERATOR BREAKER. (#9 UNIT MAY NEED TO BE RAISED TO STABLIZE PRESSURE.) WHEN UNIT IS ON LINE, PUSH "F1" TO LOCK IN PRESSURE (CASCADE MODE). RAISE LOAD ON #9 UNIT SLOWLY TO LOAD UP BOTH UNITS. ☐

NOTE: DO NOT OPEN DAMPER MORE THAN 25% UNTIL YOU ARE READY TO COME ON-LINE WITH UNIT. BEFORE OPENING DAMPER COMPLETELY, #9 MUST BE BELOW 1 MW OR DAMAGE TO DAMPER CABLES MAY OCCUR.

40. WHEN LOAD IS APPROXIMATELY 3 MWS, OPEN EXTRACTION TO DA. ☐

41. OPEN VALVE BEFORE STAGE HEATER SLOWLY. ☐

42. CHECK LUBE OIL TEMP (BETWEEN 100 AND 110 DEG. F) - CLOSE TURBINE DRAINS. ☐

43. WHEN YOU HAVE 4 TO 5 MWS ON #5, TAKE HOG OUT OF SERVICE. MAKE SURE VACUUM REMAINS STABLE. ☐

44. CHECK AUX. LUBE OIL PUMP,(NOT RUNNING AND IN "AUTO".) ☐

45. CLOSE OFF COOLING WATER TO FLASH TANK. ☐

46. CLOSE OFF VALVES FOR PEGGING STEAM TO DEAERATER. ☐

47. WHEN UNIT HAS STABLIZED, FINISH RAISING PRESSURE ON #9 BOILER BY GOING TO "06" ON THE TRI-SEN. PUSH "ENTER", THEN ENTER A PRESSURE SETTING THAT IS 5 LBS. HIGHER THAN WHAT IS LOCKED IN. PUSH "ENTER" AGAIN. THIS WILL RAISE #9 BOILER PRESSURE BY 5 LBS. CONTINUE THIS PROCEDURE UNTIL "THROTTLE" PRESSURE GAUGE ON #5 TURBINE BOARD READS 400 LBS. ☐

NOTE: MAKE SURE ALL PRESSURE ADJUSTMENTS ARE ENTERED CORRECTLY BEFORE PUSHING "ENTER" ON TRI-SEN.

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#9 AND #5 START-UP LIST

Date ___________

48. WHEN LOAD PERMITS - PUT NOX AND AUG ON G.T. (WHEN NEEDED.) ☐

49. PUT BOWSER TANK IN SERVICE (IF NOT ALREADY IN SERVICE.) ☐

50. CHECK FOR ANY FLAGS ON TARGETS BEHIND CONTROL PANEL.

51. CHECK FOR THINGS OVERLOOKED. ☐

NOTES

AUXILIARY OPERATOR ______________________

CONTROL/BOILER OPERATOR ______________________

WATCH ENGINEER ______________________

DATE ______________________

PREPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.
M. Vorlz	HR	POWER PLANT	10/92	0

NO. 7 BOILER PRELIGHT CHECKLIST

PURPOSE

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

SCOPE

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

POLICY

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

GENERAL

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

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

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NO. 7 BOILER PRELIGHT CHECKLIST

OPER 1. DRUM LEVEL IS UP TO FIRING LEVEL (1 BUBBLE IN SIGHTGLASS.)

OPER 2. CHECK ALARM PANELS IN BOILER ROOM AND TURBINE PANEL, TEST ALARMS, REPLACE BULBS AS NECESSARY. PLACE MOLYTEKS IN AUTO MODE (BOILER ROOM AND TURBINE BOARD.)

OPER 3. CHECK FOR TAGS ON EQUIPMENT IN BOILER ROOM, AT TURBINE PANEL AND IN 2400 SWITCHGEAR ROOM. NOTIFY WATCH ENGINEER OF ANY TAGS ON ANY EQUIPMENT.

OPER 4. REMOVE NITROGEN BLANKET OFF BOILER, CLOSE VALVE AT BOILER VENT AND SHUT FLOW OFF AT SCAVENGER.

OPER 5. OPEN BOILER VENTS (3)- SUPERHEATER, SPRAY HEADER, AND NORTH DRUM VENTS.

OPER 6. OPEN BOILER DRAINS (3)- MAIN, BEFORE AND AFTER SPRAY-HEADER DRAINS; UPSTREAM AND DOWNSTREAM VALVES.

OPER 7. VALVES BEFORE AND AFTER ATTEMPERATOR CONTROL REG. ARE OPEN (BYPASS CLOSED) AND UPSTREAM VALVE OPEN.

OPER 8. VALVES BEFORE AND AFTER FEEDWATER REGULATOR ARE OPEN, AND FEEDWATER REGULATOR IS IN AUTO POSITION AT REGULATOR.

OPER 9. CHECK POSITION OF FEEDWATER STOP VALVE AT DRUM.

OPER 10. INSPECT ALL BOILER ENTRANCE DOORS TO MAKE SURE THEY ARE SECURE, AND NO WATER APPEARS FROM BOILER DRUM HATCHES.

OPER 11. NORTH AND SOUTH BOILER BLOWDOWN VALVES SHOULD BE CLOSED. BLOWDOWNS SHOULD BE LINED UP TO FLASH TANK.

OPER 12. NORTH AND SOUTH SIDE WATERWALL HEADER DRAINS SHOULD BE CLOSED.

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

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

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

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

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

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

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#8 UNIT SHUTDOWN PROCEDURE

1 Boiler room lowers boiler pressure 50 to 100 psi. (from 1250 to 1150 psi)

2 Control room lowers generator to about 3 megawatts.

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

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

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

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

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

8 Shift supervisor places turbine-generator on turning gear once the turbine rolls down to zero speed.

9 Once the boiler has completed its 5 min. purge the FD fan is shut down and all gas valves are closed pertaining to the unit.

#7 UNIT SHUTDOWN PROCEDURE

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

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

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

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

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

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

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

8 Shift supervisor places turbine-generator on turning gear once the turbine rolls down to zero speed.

9 Once the boiler has completed its 5 min. purge the FD fan is shut down and all gas valves are closed pertaining to the unit.

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#9 and #5 SHUTDOWN PROCEDURE

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

2 Control room operator close the HRSG damper.

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

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

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

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

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

DIESEL SHUTDOWN PROCEDURES

1 Control room operator turns start/stop switch to 'stop' postion. Unit will automatically unload and come off the line with a cool down period for the engine.

2 A operator will go to local control panel and put mode selector switch to the off position and fault indicator light should come on.

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6. CHECK THE FIELD BREAKER. MAKE SURE THAT IT IS CHARGED. ☐

7. CHECK THE GENERATOR OCB AND THE CONTROL POWER. ☐

8. CHECK THE DISCONNECTS ON THE TRANSFORMERS AND OCB'S. ☐

9. MAKE SURE THAT THE TRANSFORMERS HAVE PROPER OIL LEVELS, THAT THE FANS ARE ON AND THAT THE OIL AND WINDING TEMPS ARE O.K. ☐

10. MAKE SURE THAT THE GENERATOR HAS 15 PSI OF HYDROGEN (UNITS NO. 7 AND NO. 8.) ☐

11. MAKE SURE THAT THE BOILER ROOM HAS COMPLETED ITS CHECK OFF SHEET. ☐

12. MAKE SURE THAT THE NECESSARY LUBE OIL PUMPS ARE ON. ☐

13. BRINGING UNIT UP TO SPEED AND SYNC IS ANOTHER PROCEDURE. ☐

OPERATOR ON WATCH ____________________

WATCH ENGINEER ____________________

PREPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.:
Lawson.	TR	POWER PLANT	2-12-92	0

CONTROL ROOM

1. MAKE SURE THAT ALL TAGS ARE REMOVED IN THE CONTROL ROOM. ☐
2. CHECK BULBS ON THE CONTROL PANEL. ☐
3. CHECK THE TARGETS ON RELAYS AND THE LOCKOUTS BEFORE COMING ON THE LINE. ☐
4. MAKE SURE THAT THE PROPER CHART RECORDERS ARE ON. ☐
5. NOTIFY DISPATCH THAT WE ARE COMING ON THE LINE. ☐
6. CHECK STATION SERVICE AND REROUTE IF NECESSARY. ☐
7. PREPARE TO SYNCHRONIZE THE GENERATOR. ☐
8. CHECK THE PANEL BULBS AND THE TARGETS AFTER YOU ARE ON THE LINE. ☐

WATCH ENGINEERS

1. REVIEW PERMITS AND REMOVE ALL TAGS AND MAKE SURE THAT ALL BREAKERS ARE RACKED BACK IN. ☐
2. MAKE SURE THAT ALL THE AUXILIARY EQUIPMENT IS RACKED IN AND MEG ALL MOTORS ABOVE 50 HP, REGARDLESS OF VOLTAGE. ALSO, CHECK THE MOTOR HEATERS. ☐
3. MAKE SURE THAT THE OIL RESERVOIR IS AT THE CORRECT LEVEL. ☐
4. MAKE SURE THAT YOU ARE ON TURNING GEAR. (MIN. 12 HRS.) ☐
5. CHECK EXCITER RHEOSTAT. MAKE SURE IT IS IN THE PROPER POSITION. ☐

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

GENERATOR START-UP PROCEDURES

PURPOSE

This procedure has been prepared to serve as a guide to ensure that the generators are placed on the line in a safe and proper manner.

SCOPE

Details are listed for the responsibility of the Operator/Watch Engineer prior to putting a generator on the line. This list is not all inclusive and should not be relied on as a substitute for good operating practice based on individual experience and training.

POLICY

These checks will be performed and checked off before attempting to place a generator into service.

GENERAL

This sheet will be properly filled out by both the Operator and the Watch Engineer and then turned in to the Plant Operations Supervisor.

PREPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.:
Hanson		POWER PLANT	2-12-92	0

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NO. 8 BOILER PRELIGHT CHECK LIST (CON'T.)

COMMENTS/ACTIONS TAKEN THAT WERE NECESSARY IN ORDER TO PUT EQUIPMENT INTO SERVICE/PRELIGHT BOILER:

CONTROL/ BOILER OPER__________________

WATCH ENGINEER__________________

Date__________________

PREPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.:
[signature]	[signature]	POWER PLANT	2-12-92	0

NO. 8 BOILER PRELIGHT CHECK LIST (CON'T.)

OPER	25.	MAKE-UP PUMP IS LINED TO DA.	☐
OPER	26.	MAKE SURE WE HAVE FULL INSTRUMENT AIR PRESSURE. VALVES AT FILTERS SHOULD BE OPEN.	☐
OPER	27.	CHECK FIBERGLASS TANK LEVEL.	☐
OPER	28.	BALOMETER HAS BEEN CLEANED.	☐
OPER	29.	THERMO PROBE IS RETRACTED (UNLESS OTHERWISE INSTRUCTED BY WATCH ENGINEER.)	☐
W ENG	30.	DRUM LEVEL TRIP IS LIFTED.	☐
OPER	31.	COOLING AIR BLOWER IS ON, RESERVE IS ON STANDBY.	☐
OPER	32.	MAIN STEAM STOP VALVE IS OPEN (UNLESS OTHERWISE INSTRUCTED BY WATCH ENGINEER.)	☐
OPER	33.	CHECK IGNITOR GAS SUPPLY (12 - PSI CITY OF FLORIDA GAS.)	☐
OPER	34.	CHECK YARD GAS VALVES, OPEN S-4 VALVE AT GAS HEADER ON PLATFORM. MAKE SURE MINIMUM FLOW VALVE IS FULLY OPEN, AND THE MAIN GAS VALVE BEFORE MAIN REDUCER IS CLOSED (UNTIL WE ARE ON THE LINE.)	☐
OPER	35.	INFORM CONTROL ROOM YOU ARE GOING TO BE STARTING A FORCED DRAFT FAN.	☐
OPER	36.	START FAN AND INITIATE PURGE. CHECK FAN FOR VIBRATION AND OIL SLINGERS FOR PROPER OPERATION.	☐
OPER	37.	BE PREPARED TO PUT FIRE IN BOILER AND BRING BOILER UP AS USUAL.	☐
OPER	38.	SIGN NOX CHART (TIME FIRE WAS PUT IN BOILER.)	☐
W ENG	39.	NOTIFY FLORIDA GAS IF UNIT IS COMING ON LINE.	☐

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

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NO. 8 BOILER PRELIGHT CHECK LIST (CON'T.)

OPER	13.	CHECK OUT BOILER FEEDWATER PUMPS. (A) SUCTION AND DISCHARGE VALVES OPEN. (B) VENTS OPEN. (C) BALANCE LINE VALVES OPEN AT PUMP AND AT DA. (D) CHECK OIL LEVEL IN RESERVOIR. (E) CHECK IN BOWL FOR SHAFT PUMP SUCTION. (F) RECIRC VALVE AT DA AND VALVES AT PUMP OPEN. (G) ALL COOLING WATER VALVES OPEN. (H) AUX LUBE OIL PUMP IN AUTO. (I) RECIRC VALVES IN MANUAL OPEN POSITION IN BOILER ROOM.	☐
OPER	14.	CHECK OIL LEVELS AT FORCED DRAFT FANS AND MOTORS.	☐
OPER	15.	OPEN MANUAL FAN AND STACK DAMPERS ON FAN TO BE PLACED IN SERVICE.	☐
OPER	16.	CHECK OIL LEVELS OF AIRHEATER TRUNION BEARINGS (HOT AND COLD ENDS); ALSO, COOLING WATER TO AIRHEATER BEARINGS	☐
OPER	17.	COOLING WATER TO AIRHEATER SHAFTS ON.	☐
OPER	18.	CHECK OIL LEVELS OF AIR HEATER MOTORS AND AIR DRIVES.	☐
OPER	19.	TURN ON O2 ANALYZER AND CHECK CALIBRATION.	☐
OPER	20.	TURN ON NOX RECORDER AS USUAL.	☐
OPER	21.	CHECK OUT EACH BURNER AT FRONT. (A) PILOT IN AUTO POSITION. (B) AIR REGISTER OPERATION. (C) LIMIT SWITCHES IN PROPER POSITION. (D) COOLING AIR VALVES OPEN, SEALING VALVES CLOSED. (E) BURNER GUN OPERATION. (F) ALL OTHER RELATED EQUIPMENT.	☐
OPER	22.	CHECK FORNEY BURNER CABINETS AND NOTIFY WATCH ENGINEER OF ANY TAGS.	☐
OPER	23.	COOLING AIR VALVES TO PORTHOLES ARE OPEN.	☐
OPER	24.	HOUSE AIR COMPRESSOR IS ON (PRESS. A MIN. OF 85 PSI.)	☐

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

NO. 8 BOILER PRELIGHT CHECK LIST

OPER	1.	DRUM LEVEL IS UP TO FIRING LEVEL (1 BUBBLE IN SIGHTGLASS.)	☐
OPER	2.	CHECK ALARM PANELS IN BOILER ROOM AND TURBINE PANEL, TEST ALARMS, REPLACE BULBS AS NECESSARY. PLACE MOLYTEKS IN AUTO MODE (BOILER ROOM AND TURBINE BOARD.)	☐
W.ENG	3.	CHECK FOR TAGS ON EQUIPMENT IN BOILER ROOM, TURBINE PANEL, 2400 V BUS AND 480 V BUS.	☐
OPER	4.	TAKE NITROGEN BLANKET OFF BOILER, CLOSE VALVE AT BOILER AND SHUT FLOW OFF AT SCAVENGER.	☐
OPER	5.	CHECK ALL BOILER ENTRANCE DOORS TO MAKE SURE THEY ARE SECURE, MAKE SURE THERE IS NO WATER LEAKAGE FROM BOILER DRUM HATCHES AND THAT THEY ARE SECURE.	☐
OPER	6.	OPEN BOILER VENTS (3) SUPERHEATER OUTLET, AFTER SPRAY HEADER, AND NORTH DRUM VENT.	☐
OPER	7.	OPEN BOILER DRAINS (2) MAIN, SPRAY HEADER DRAIN (UPSTREAM AND DOWNSTREAM VALVES.)	☐
OPER	8.	VALVES BEFORE AND AFTER ATTEMPERATOR ARE OPEN (BY-PASS CLOSED,) AND DOWNSTREAM VALVE AT TOP OF BOILER OPEN.	☐
OPER	9.	VALVES OPEN BEFORE AND AFTER FEEDWATER REGULATOR (BYPASS VALVE CLOSED.)	☐
OPER	10.	CHECK POSITION OF FEEDWATER STOP VALVE.	☐
OPER	11.	NORTH AND SOUTH BOILER BLOWDOWN VALVES SHOULD BE CLOSED. BLOWDOWNS SHOULD BE LINED UP TO FLASH TANK.	☐
OPER	12.	NORTH AND SOUTH SIDE WATERWALL HEADER DRAINS SHOULD BE CLOSED.	☐

PREPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.:
[signature]	[initials]	POWER PLANT	2-12-92	0

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NO. 8 BOILER PRELIGHT CHECK LIST

PURPOSE

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

SCOPE

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

POLICY

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

GENERAL

The No. 8 Boiler Prelight Check List for the prospective unit will be properly filled out by both the Operator and the Watch Engineer and then turned in to the Plant Operations Supervisor.

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

6. CHECK THE FIELD BREAKER. MAKE SURE THAT IT IS CHARGED. ☐
7. CHECK THE GENERATOR OCB AND THE CONTROL POWER. ☐
8. CHECK THE DISCONNECTS ON THE TRANSFORMERS AND OCB'S. ☐
9. MAKE SURE THAT THE TRANSFORMERS HAVE PROPER OIL LEVELS, THAT THE FANS ARE ON AND THAT THE OIL AND WINDING TEMPS ARE O.K. ☐
10. MAKE SURE THAT THE GENERATOR HAS 15 PSI OF HYDROGEN (UNITS NO. 7 AND NO. 8.) ☐
11. MAKE SURE THAT THE BOILER ROOM HAS COMPLETED ITS CHECK OFF SHEET. ☐
12. MAKE SURE THAT THE NECESSARY LUBE OIL PUMPS ARE ON. ☐
13. BRINGING UNIT UP TO SPEED AND SYNC IS ANOTHER PROCEDURE. ☐

OPERATOR ON WATCH____________________

WATCH ENGINEER____________________

PREPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.:
[signature]	[signature]	POWER PLANT	2-12-92	0

CONTROL ROOM

1. MAKE SURE THAT ALL TAGS ARE REMOVED IN THE CONTROL ROOM. ☐
2. CHECK BULBS ON THE CONTROL PANEL. ☐
3. CHECK THE TARGETS ON RELAYS AND THE LOCKOUTS BEFORE COMING ON THE LINE. ☐
4. MAKE SURE THAT THE PROPER CHART RECORDERS ARE ON. ☐
5. NOTIFY DISPATCH THAT WE ARE COMING ON THE LINE. ☐
6. CHECK STATION SERVICE AND REROUTE IF NECESSARY. ☐
7. PREPARE TO SYNCHRONIZE THE GENERATOR. ☐
8. CHECK THE PANEL BULBS AND THE TARGETS AFTER YOU ARE ON THE LINE. ☐

WATCH ENGINEERS

1. REVIEW PERMITS AND REMOVE ALL TAGS AND MAKE SURE THAT ALL BREAKERS ARE RACKED BACK IN. ☐
2. MAKE SURE THAT ALL THE AUXILIARY EQUIPMENT IS RACKED IN AND MEG ALL MOTORS ABOVE 50 HP, REGARDLESS OF VOLTAGE. ALSO, CHECK THE MOTOR HEATERS. ☐
3. MAKE SURE THAT THE OIL RESERVOIR IS AT THE CORRECT LEVEL. ☐
4. MAKE SURE THAT YOU ARE ON TURNING GEAR. (MIN. 12 HRS.) ☐
5. CHECK EXCITER RHEOSTAT. MAKE SURE IT IS IN THE PROPER POSITION. ☐

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

GENERATOR START-UP PROCEDURES

PURPOSE

This procedure has been prepared to serve as a guide to ensure that the generators are placed on the line in a safe and proper manner.

SCOPE

Details are listed for the responsibility of the Operator/Watch Engineer prior to putting a generator on the line. This list is not all inclusive and should not be relied on as a substitute for good operating practice based on individual experience and training.

POLICY

These checks will be performed and checked off before attempting to place a generator into service.

GENERAL

This sheet will be properly filled out by both the Operator and the Watch Engineer and then turned in to the Plant Operations Supervisor.

PREPARED BY:	APPROVED BY:	H. D. KING	DATE ISSUED:	REVISION NO.:
Hauser	HL	POWER PLANT	2-12-92	0

COMMENTS/ACTIONS TAKEN THAT WERE NECESSARY IN ORDER TO PUT EQUIPMENT INTO SERVICE/PRELIGHT BOILER:

CONTROL/BOILER OPERATOR ______________________

SHIFT WATCH ENGINEER ______________________

Date ______________

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

Attachment F

CURRENT TITLE V PERMIT (INCLUDING ACID RAIN PERMIT)

RECEIVED
OCT 25 2000
FORT PIERCE UTILITIES AUTHORITY
DIRECTOR OF OPERATIONS

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

NOTICE OF ADMINISTRATIVELY CORRECTED TITLE V OPERATION PERMIT

In the Matter of a Request for Administrative Correction:

Mr. Thomas W. Richards
Director of Operations
Ft. Pierce Utilities Authority
P. O. Box 3191
Ft. Pierce, Florida 34948

FINAL Permit No.: 1110003-003-AV
H. D. King Plant

Enclosed is an ADMINISTRATIVELY CORRECTED page to the initial Title V operation permit, 1110003-003-AV for the operation of the H. D. King Power Plant located at 311 North Indian River Drive, Ft. Pierce, St. Lucie County. This correction is issued pursuant to Rule 62-210.360, Florida Administrative Code and Chapter 403, Florida Statutes (F.S.). This change is made at the applicant's request of September 20, 2000 to change the rating description of Emissions Unit I.D. 007 to read 37.5 megawatts, wherever it appears in the permit. This corrective action does not alter the effective dates of the existing permit.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and, by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

for C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF ADMINISTRATIVELY CORRECTED PERMIT (including the corrected page(s)) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 10/23/00 to the person(s) listed or as otherwise noted:

Mr. Isidore Goldman, PE, FDEP, SED
Mr. Tom Tittle, FDEP SED
Mr. Gregg Worley, U.S. EPA, Region 4 (INTERNET E-mail Memorandum)
Ms. Elizabeth Bartlett, U.S. EPA, Region 4 (INTERNET E-mail Memorandum

Clerk Stamp

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

Barbara J. Friday 10/23/00
(Clerk) (Date)

Section I. Facility Information., Subsection A., Facility Description. is changed, as follows:

From: This facility consists of one 16.5 megawatt (electric) 219 million Btu per hour fossil fuel fired steam generator; one 33 megawatt (electric) 470 million Btu per hour fossil fuel fired steam generator; one 56.1 megawatt (electric) 611 million Btu per hour fossil fuel fired steam generator; and one 23.4 megawatt (electric) combined cycle gas turbine with a 8.2 megawatt (electric) heat recovery steam generator (HRSG).

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

Section I. Facility Information., Subsection B. Summary of Emissions Unit ID No(s). and Brief Description(s). is changed, as follows:

From:

E.U. ID No.	Brief Description
-003	23.4 MW Combined Cycle Gas Turbine with 8.2 MW HRSG - Unit #9
-004	16.5 MW Boiler - Unit #6
-007	33.0 MW Boiler - Unit #7
-008	56.1 MW Boiler - Unit #8

To:

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

Section III. Emissions Unit(s) and Conditions., Subsection C. This section addresses the following emissions unit. is changed, as follows:

From:

E.U. ID No.	Brief Description
-007	33.0 MW Boiler - Unit #7

Fossil fuel fired steam generator # 7 is a nominal 33.0 megawatt (electric) steam generator designated as H. D. King Unit # 7. The emission unit is fired on natural gas with a maximum heat input of 470.0 MMBtu per hour. No. 2 fuel oil is fired as a secondary/emergency fuel. Emissions are discharged through a multicyclone collector.

To:

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

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

Section IV. This section is the Acid Rain Part., Subsection A. This subsection addresses Acid Rain, Phase II. is changed, as follows:

From:

E.U. ID No.	**Brief Description**
-007	33.0 MW Boiler - Unit #7
-008	56.1 MW Boiler - Unit #8

To:

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

STATEMENT OF BASIS

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

Title V Air Operation Permit Revision
FINAL Title V Permit Revision No.: 1110003-004-AV

The initial Title V air operation permit went final on December 31, 1997 and effective on January 1, 1998. This Title V air operation permit with 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.

The subject of the permit revision is to incorporate the request of Ft. Pierce Utilities Authority to eliminate No. 6 residual fuel oil, where previously permitted, and substitute the use of No. 2 fuel oil at the plant. This will result in a decrease in actual sulfur dioxide emissions when fuel oil is combusted.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF FINAL PERMIT

In the Matter of an
Application for Permit by:

Mr. Thomas W. Richards
Director of Operations
Fort Pierce Utilities Authority
P. O. Box 3191
Fort Pierce, Florida 34948

FINAL Permit No.: 1110003-004-AV
H. D. King Power Plant

Enclosed is FINAL Title V Permit Revision No.: 1110003-004-AV for the operation of the H. D. King Power Plant located at 311 North Indian River Drive, Fort Pierce, St. Lucie County, issued pursuant to Chapter 403, Florida Statutes (F.S.).

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the permitting authority in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the permitting authority.

Executed in Tallahassee, Florida.

for Scott M. Sheplak

C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 6/27/00 to the person(s) listed or as otherwise noted:

Mr. Thomas W. Richards*
Mr. George Miller, Ft. Peirce Utilities Authority
Mr. Isidore Goldman, PE, FDEP SED
Mr. Gregg Worley, USEPA, Region 4 (INTERNET E-mail Memorandum)
Ms. Elizabeth Bartlett, USEPA, Region 4 (INTERNET E-mail Memorandum)

Clerk Stamp

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

Barbara J. Boutwell 6/27/00

(Clerk) (Date)

FINAL PERMIT DETERMINATION

FINAL Title V Permit Revision No.: 1110003-004-AV
Page 1 of 1

I. Comment(s).

No comments were received from USEPA during their 45 day review period of the PROPOSED permit.

II. Conclusion.

Since there were no comments received during the USEPA 45 day review period, no changes were made to the PROPOSED Title V Permit Revision and the permitting authority hereby issues the FINAL Title V Permit Revision No.: 1110003-004-AV.

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

Title V Air Operation Permit Revision
FINAL Title V Permit Revision No.: 1110003-004-AV

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

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

Telephone: 850/488-1344
Fax: 850/922-6979

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

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POWER GENERATION

Title V Air Operation Permit Revision
FINAL Title V Permit Revision No.: 1110003-004-AV

Table of Contents

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

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

FINAL Title V Permit Revision No.: 1110003-004-AV
Facility ID No.: 1110003
SIC Nos.: 49, 4911
Project: Title V Air Operation Permit Revision

This permit with revision is for the operation of the H. D. King Power Plant. This facility is located at 311 North Indian River Drive, Fort Pierce, St. Lucie County; UTM Coordinates: Zone 17, 566.8 km East and 3036.3 km North; Latitude: 27° 27' 00" North and Longitude: 80° 19' 26" West.

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.

Referenced attachments made a part of this permit:
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix TV-3, Title V Conditions (version dated 04/30/99)
APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)
TABLE 297.310-1, CALIBRATION SCHEDULE (version dated 10/07/96)
FIGURE 1 - SUMMARY REPORT-GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE REPORT (40 CFR 60; July 1996)
Phase II Acid Rain Application/Compliance Plan received 12/18/95
Alternate Sampling Procedure: ASP Number 97-B-01
OGC Case No. 91-1610. Final Order filed 7/21/92

Effective Date: January 1, 1998
Title V Permit Revision Effective Date: May 25, 2000
Renewal Application Due Date: July 5, 2002
Expiration Date: December 31, 2002

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

HLR/sms/es

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of one 16.5 megawatt (electric) 219 million Btu per hour fossil fuel fired steam generator; one 33 megawatt (electric) 470 million Btu per hour fossil fuel fired steam generator; one 56.1 megawatt (electric) 611 million Btu per hour fossil fuel fired steam generator; and one 23.4 megawatt (electric) combined cycle gas turbine with a 8.2 megawatt (electric) heat recovery steam generator (HRSG).

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

Based on the initial Title V permit application received June 14, 1996, this facility is not a major source of hazardous air pollutants (HAPs).

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

E.U. ID No.	Brief Description
-003	23.4 MW Combined Cycle Gas Turbine with 8.2 MW HRSG - Unit #9
-004	16.5 MW Boiler - Unit #6
-007	33.0 MW Boiler - Unit #7
-008	56.1 MW Boiler - Unit #8

Unregulated Emissions Units and/or Activities

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

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

Subsection C. Relevant Documents.

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

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 the permitting authority:
Initial Title V Permit Application received June 14, 1996
Additional Information Request dated January 27, 1997
Additional Information Response received February 24, 1997
Letter received July 18, 1997, from Mr. Thomas W. Richards.
Letter received November 6, 1997, from Mr. Thomas W. Richards.
Request for revision received December 2, 1999, from Mr. Edward S. Leongomez

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

4. Prevention of Accidental Releases (Section 112(r) of CAA). If required by 40 CFR 68, the permittee shall submit to the implementing agency:
   a. a risk management plan (RMP) when, and if, such requirement becomes applicable; and
   b. certification forms and/or RMPs according to the promulgated rule schedule.
[40 CFR 68]

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

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

7. General Pollutant Emission Limiting Standards. Volatile Organic Compounds (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.]

8. Not federally enforceable. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include: paved fuel delivery roads and parking lots.
[Rule 62-296.320(4)(c)2., F.A.C.; Proposed by applicant in the initial Title V permit application received June 14, 1996]

9. 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 51., APPENDIX TV-3, TITLE V CONDITIONS}
[Rule 62-214.420(11), F.A.C.]

10. 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.]

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

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

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

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

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Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions unit.

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

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

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

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

Essential Potential to Emit (PTE) Parameters

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

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

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

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

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

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

Emission Limitations and Standards

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

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

where:

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

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

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

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

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

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

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Excess Emissions

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

A.11. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

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

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

Monitoring of Operations

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

A.14. The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:
(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.
(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with 40 CFR 60.334(b).
[40 CFR 60.334(b)(1) & (2)]

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A.15. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

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

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

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

$$NO_X = [NO_X \, obs] \, [(P_{ref}) / P_{obs}]^{0.5} \; e^{19(H_{obs} - 0.00633)} \; [288^0 \, K / T_{amb}]^{1.53}$$

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

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

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

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

e = Transcendental constant (2.718)

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

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

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

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

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

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

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

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

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

A.25. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity (i.e., at less than 90 percent of the maximum operation rate allowed by the permit); in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted, provided however, operations do not exceed 100 percent of the maximum operation rate allowed by the permit. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rule 62-297.310(2), F.A.C. and 1110003-002-AO]

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

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

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

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

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

(a) General Compliance Testing.

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

a. Did not operate; or

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

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

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

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

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

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

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

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

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

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

Record Keeping and Reporting Requirements

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

A.32. The owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form [see 40 CFR 60.7(d)] to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or, the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or, the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information:
(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
[40 CFR 60.7(c)(1), (2), (3), & (4)]

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A.33. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.
(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.
(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.
[40 CFR 60.7(d)(1) & (2)]

A.34. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

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

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

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

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

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

Miscellaneous Requirements.

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

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

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Section III. Emissions Unit(s) and Conditions.

Subsection B. This section addresses the following emissions unit.

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

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

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

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

Essential Potential to Emit (PTE) Parameters

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

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

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

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

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

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

Emission Limitations and Standards

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

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

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

B.6. Visible emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.
[Rule 62-210.700(3), F.A.C.]

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

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

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

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

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

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

Excess Emissions

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

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

B.15. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

B.16. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310([illegible]), F.A.C.]

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Test Methods and Procedures

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

B.30. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.
2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.
3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
a. Did not operate; or

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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Record keeping and Reporting Requirements

B.33. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

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

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

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
12. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.

18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

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

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

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

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

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Section III. Emissions Unit(s) and Conditions.

Subsection C. This section addresses the following emissions unit.

<u>E.U. ID No.</u>	<u>Brief Description</u>
-007	33.0 MW Boiler - Unit #7

Fossil fuel fired steam generator # 7 is a nominal 33.0 megawatt (electric) steam generator designated as H. D. King Unit # 7. The emission unit is fired on natural gas with a maximum heat input of 470.0 MMBtu per hour. No. 2 fuel oil is fired as a secondary/emergency fuel. Emissions are discharged through a multicyclone collector.

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

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

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

C.1. <u>Permitted Capacity</u>. The maximum operation heat input rate is as follows:

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

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

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

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

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

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

Emission Limitations and Standards

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

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

C.6. Visible emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.
[Rule 62-210.700(3), F.A.C.]

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

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

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

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

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

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

Excess Emissions

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

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

C.15. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

C.16. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

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

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

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

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

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

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

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

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

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

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

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

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

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

C.28. Applicable Test Procedures.

(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached to this permit.

(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

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

C.29. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.

[Rule 62-297.310(6), F.A.C.]

C.30. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.

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

a. Did not operate; or

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

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

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

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

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

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

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

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

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

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

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

a. only gaseous fuel(s); or

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

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

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

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

a. only gaseous fuel(s); or

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

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

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

Record keeping and Reporting Requirements

C.33. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

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

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

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

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

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

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

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

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

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

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Section III. Emissions Unit(s) and Conditions.

Subsection D. This section addresses the following emissions unit.

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

H. D. King Unit #8 is a nominal 56.1 megawatt (electric) fossil fuel fired steam generator. The emission unit is fired on natural gas with a maximum heat input of 611.0 MMBtu per hour. No. 2 fuel oil is fired as a secondary/emergency fuel. Emissions are uncontrolled.

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

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
8	611.0	Natural Gas
	611.0	No. 2 Fuel Oil

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

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

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

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

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

Emission Limitations and Standards

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

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

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

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

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

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

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

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

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

Excess Emissions

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

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

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

D.16. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

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

Monitoring of Operations

D.17 Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

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

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

D.19. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:
i. EPA Method 9, Section 2.4, Recording Observations. Opacity observations shall be made and recorded by a certified observer at sequential fifteen second intervals during the required period of observation.

2. EPA Method 9, Section 2.5, Data Reduction. For a set of observations to be acceptable, the observer shall have made and recorded, or verified the recording of, at least 90 percent of the possible individual observations during the required observation period. For single-valued opacity standards (e.g., 20 percent opacity), the test result shall be the highest valid six-minute average for the set of observations taken. For multiple-valued opacity standards (e.g., 20 percent opacity, except that an opacity of 40 percent is permissible for not more than two minutes per hour) opacity shall be computed as follows:

a. For the basic part of the standard (i.e., 20 percent opacity) the opacity shall be determined as specified above for a single-valued opacity standard.

b. For the short-term average part of the standard, opacity shall be the highest valid short-term average (i.e., two-minute, three-minute average) for the set of observations taken.

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

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

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

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

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

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

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

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

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

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

(2) Method 5 shall be used to determine the particular matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems.
(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train may be set to provide a gas temperature no greater than 160 ± 14 °C (320 ± 25 °F).
(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration ($\%O_2$). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all the individual O_2 sample concentrations at each traverse point.
(iii) If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points.
(3) Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity.
(4) Method 6 shall be used to determine the SO_2 concentration.
(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.
(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration ($\%O_2$). The O_2 sample shall be taken simultaneously with, and at the same point as, the SO_2 sample. The SO_2 emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

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

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

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

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

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

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

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

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

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

where:

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

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

$\%\,CO_2$ = carbon dioxide concentration, percent dry basis.

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

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

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

(B) When F_o is less than 0.97 F_{oa} and when the average difference ($\bar{d}$) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if F_o is 0.9[illegible] F_{oa}, E shall be increased by [illegible] percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

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

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

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

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

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

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

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

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

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

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

D.28. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

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

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

D.31. Applicable Test Procedures.
(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached to this permit.
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

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

D.33. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid fuel for more than 400 hours other than during startup.

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

a. Did not operate; or

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

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

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

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

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

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

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

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.
(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.; and, SIP approved]

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

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

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

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

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

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

Continuous Monitoring Requirements

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

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

[In parts per million]

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

{1}Not applicable.

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

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

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

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

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

where:

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

[40 CFR 60.45(e)(1)]

D.39. The values used in the equations under 40 CFR 60.45(e) (1) are derived as follows:
(1) E = pollutant emissions, ng/J (lb/million Btu).
(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for sulfur dioxide and 46.01 for nitrogen oxides.
(3) % O_2, % CO_2 = oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under 40 CFR 60.45(a).
(4) F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476×10^{-7} dscm/J (9,220 dscf/million Btu) and F_c = 0.384×10^{-7} scm CO_2 /J (1,430 scf CO_2 /million Btu).

(iv) For gaseous fossil fuels, F = 2.347×10^{-7} dscm/J (8,740 dscf/million Btu). For natural gas, propane, and butane fuels, F_c = 0.279×10^{-7} scm CO_2 /J (1,040 scf CO_2 /million Btu) for natural gas, 0.322×10^{-7} scm CO_2 /J (1,200 scf CO_2/million Btu) for propane, and 0.338×10^{-7} scm CO_2 /J (1,260 scf CO_2 /million Btu) for butane.

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

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

$$F_c = \frac{2.0\times10^{-5}\ (\text{pct. C})}{GCV}$$

(SI units)

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

(English units)

$$F_c = \frac{321x10^3\ (\%C)}{GCV}$$
(English units)

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

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

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

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

Recordkeeping and Reporting Requirements

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

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D.41. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

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

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

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

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

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

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

D.45. The permittee must notify the DEP within 24 hours after commencement of oil firing and furnish the following information:

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

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

Miscellaneous Requirements.

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

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

Subsection E. Common Conditions.

E.U. ID No.	Brief Description
-004	16.5 MW Boiler - Unit #6
-007	33.0 MW Boiler - Unit #7
-008	56.1 MW Boiler - Unit #8

The following conditions apply to the emissions units listed above:

Essential Potential to Emit (PTE) Parameters

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

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

Emission Limitations and Standards

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

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

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

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Section IV. This section is the Acid Rain Part.

Operated by: Fort Pierce Utilities Authority
ORIS code: 658

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

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

E.U. ID No.	Brief Description
-007	33.0 MW Boiler - Unit #7
-008	56.1 MW Boiler - Unit #8

A.1. The Phase II permit application(s) submitted for this facility, as approved by the Department, are a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application(s) listed below:

a. DEP Form No. 62-210.900(1)(a), dated 07/01/95.

[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

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

E.U. ID No.	EPA ID	Year	2000	2001	2002
-007	ID No. 07	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	63*	63*	63*
-008	ID No. 08	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	26*	26*	26*

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

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

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

A.5. 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, F.A.C.
[40 CFR 70.6(a)(4)(i); and, Rule 62-213.440(1)(c)1., F.A.C.]

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

A.7. Comments, notes, and justifications: None.

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

Ft. Pierce Utilities Authority **FINAL Title V Permit Revision No.:** 1110003-004-AV
H. D. King Power Plant **Facility ID No.:** 1110003

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

The below listed emissions units and/or activities are r ıor 'insignificant emissions units'.

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

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

Ft. Pierce Utilities Authority FINAL Title V Permit Revision No.: 1110003-004-AV
H. D. King Power Plant Facility ID No.: 1110003

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, 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. [illegible] itle V source; however, such emissions units and activities shall be [illegible] purposes provided they also meet the criteria of Rule 62-213.430(6)(b), [illegible] entitled to an exemption from permitting under Rule 62.210.300(3 [illegible] ibination with the emissions of other units and activities at the facility, [illegible] ave the potential to emit any pollutant in such amount as to make the f [illegible]

The below listed emissions units and/or activities are [illegible] Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities

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

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