LAKELAND ELECTRIC

Farzie Shelton, chE; REM

Environmental Affairs Manager of Licensing & Permitting

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FEB 28 2000

BUREAU OF AIR REGULATION

February 24, 2000

Mr. C.H. Fancy, P.E.
Chief Bureau of Air Regulation
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road, Mail Station #5505
Tallahassee, Florida 32399-2400

Re: Larsen Memorial Power Plant Facility Identification Number 1050003
Request to Revise Unit No. 8 Permit No. PSD-FL-166

Dear Mr. Fancy:

The City of Lakeland Department of Electric Utilities (Lakeland) requests revision to the above-referenced Prevention of Significant Deterioration (PSD) permit for the Larsen memorial Power Plant Unit No. 8 combustion turbine. This request involves installation of direct water spray fogging system that will reduce the turbine inlet air temperature. Due to cooler-denser inlet air, the combustion turbine will have better heat rate thereby increase in power output. However, the net emissions change from this project will not result in an increase of any regulated pollutant greater than the PSD significant emission rates.

Accordingly, we are submitting completed DEP Form No. 62-210.900(1) for the Department's review and appreciate your cooperation in this matter. If you should have any questions, please do not hesitate to contact me.

Sincerely,

Farzie Shelton

Cc: A. A. Linero, DEP-BAR
Ken Kosky, Golder

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FEB 25 2000

BUREAU OF AIR REGULATION

APPLICATION FOR AIR PERMIT
INSTALLATION OF DIRECT WATER SPRAY FOGGING SYSTEM
LARSEN UNIT 8

Prepared For:

Lakeland Electric
501 East Lemon Street
Lakeland, Florida 33801-5079

Prepared By:

Golder Associates Inc.
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653

February 2000
0037503Y/F1/WP

DISTRIBUTION:

6 Copies - Lakeland Electric
1 Copy - Golder Associates Inc.

PART I

APPLICATION FOR AIR PERMIT
LONG FORM

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: **City of Lakeland, Department of Electric Utilities**	
2. Site Name: **Charles Larsen Memorial Power Plant**	
3. Facility Identification Number: **1050003**	[ ] Unknown
4. Facility Location: Street Address or Other Locator: **2002 East Hwy 92** City: **Lakeland** County: **Polk** Zip Code: **33802**	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: **Ms. Farzie Shelton, Manager of Environmental Licensing and Permitting**
2. Application Contact Mailing Address: Organization/Firm: **Lakeland Electric** Street Address: **501 E. Lemon Street** City: **Lakeland** State: **FL** Zip Code: **33801-5079**
3. Application Contact Telephone Numbers: Telephone: **(834) 499 - 6603** Fax: **(834) 603 - 6335**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	February 25, 2000
2. Permit Number:	1050003-007-AC
3. PSD Number (if applicable):	PSD-FL-166 C
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

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

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

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

Current construction permit number: ______________________________

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

Current construction permit number: ______________________________

Operation permit number to be revised: ______________________________

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

Operation permit number to be revised/corrected: ______________________

[ ] 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: ______________________________

Reason for revision: ____

Air Construction Permit Application

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

[X] 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: **Ronald W. Tomlin, Assistant Managing Director**
2.	Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: **Lakeland Electric** Street Address: **501 East Lemon Street** City: **Lakeland** State: **FL** Zip Code: **33801-5079**
3.	Owner/Authorized Representative or Responsible Official Telephone Numbers: Telephone: **(834) 499 - 6300** Fax: **(834) 499 - 6344**
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 [ ], 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.* Ronald Tomlin 2-23-00 Signature Date

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1.	Professional Engineer Name: **Kennard F. Kosky** Registration Number: **14996**
2.	Professional Engineer Mailing Address: Organization/Firm: **Golder Associates Inc.** Street Address: **6241 NW 23rd Street, Suite 500** City: **Gainesville** State: **FL** Zip Code: **32653-1500**
3.	Professional Engineer Telephone Numbers: Telephone: **(352) 336 - 5600** Fax: **(352) 336 - 6603**

4. Professional Engineer Statement:

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

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

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

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ], 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 [X], 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   Feb. 21, 2000
Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
008	Combined Cycle Combustion Turbine	AC1B	

Application Processing Fee

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

Construction/Modification Information

1. Description of Proposed Project or Alterations: **Installation of direct water spray inlet fogging systems. Since the facility holds a Title V permit pursuant to Chapter 62-213 F.A.C., a permit fee is not required. Refer to Part II for discussion.**	
2. Projected or Actual Date of Commencement of Construction: **Apr 2000**	
3. Projected Date of Completion of Construction: **Jun 2000**	

Application Comment

The combustion turbine associated with Larsen Unit 8 will be installed with a direct water spray fogging system that will reduce the turbine inlet air temperature. The temperature reduction will improve the heat rate and increase power due to the cooler-denser inlet air. The net emissions change from this project will not result in an increase of any regulated pollutant greater than the PSD significant emission rates. PSD review does not apply to proposed project. Discussed in Part II.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17**	East (km): **408.9**	North (km): **3102.5**	
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **28 / 2 / 56**		Longitude (DD/MM/SS): **81 / 55 / 25**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **A**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment (limit to 500 characters): **The existing Larsen plant consists of 2 Fossil Fuel Fired Steam Generators (Units 6 and 7), 3 simple cycle gas turbines, and 1 Combined Cycle Unit (Unit 8). The combined cycle unit consists of a combustion turbine and an associated heat recovery steam generator (HRSG). The primary fuel for the combustion turbine is natural gas with the distillate oil as back-up. Refer to Part II for discussion.**			

Facility Contact

1. Name and Title of Facility Contact: **Farzie Shelton, Manager, Environmental Licensing and Permitting**		
2. Facility Contact Mailing Address: Organization/Firm: **Lakeland Electric** Street Address: **501 East Lemon Street** City: **Lakeland**	State: **FL**	Zip Code: **33801-5079**
3. Facility Contact Telephone Numbers: Telephone: (**834**) **499 - 6603**	Fax: (**834**) **603 - 6335**	

Facility Regulatory Classifications

Check all that apply:

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

List of Applicable Regulations

Facility emissions covered under existing Title V permit, no additional facility or emission unit applicable requirements as a result of the proposed change.	
See Attachment B for specific conditions for Unit 8.	

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

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [ ] Attached, Document ID:________ [ ] Not Applicable
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [ ] Equipment/Activities On site but Not Required to be Individually Listed [ ] Not Applicable
10. Alternative Methods of Operation: [ ] Attached, Document ID:________ [ ] Not Applicable
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [ ] Not Applicable
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [ ] 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:________________________) [ ] Not Applicable
14. Compliance Report and Plan: [ ] Attached, Document ID:________ [ ] Not Applicable
15. Compliance Certification (Hard-copy Required): [ ] Attached, Document ID:________ [ ] Not Applicable

PART II

SUPPORTING INFORMATION

Part II

Application for Air Permit
Installation of Direct Water Spray Fogging Systems
Martin Plant

Introduction

Lakeland Electric is proposing to install direct water spray fogging system in the inlet duct of the combustion turbine in combined cycle configuration at the Larsen Plant. The purpose of the inlet fogger is to provide adiabatic inlet air cooling which increases turbine output and decreases heat rate. The project is part of increasing capacity in a cost effective manner.

Description

Direct inlet fogging systems achieve adiabatic cooling using water to form fine droplets (fog). The fog is produced by injection grids placed in the turbine inlet duct that use nozzles that produce a fine spray. The small fog particles (about 10 to 20 microns) extract the latent heat of vaporization from the gas stream when the water droplet is converted to gas. Heat is removed at a rate of 1,075 Btu/lb of water. The result of the fogging is a cooler more moisture laden air stream. Figure 1 presents a schematic of a typical fogging system.

The amount of heat removed is highly dependent upon the ambient air conditions. The two most important parameters are the dry bulb temperature and relative humidity. As moisture is added to the inlet air by the fogging, the vaporization of the fog droplets cools the air toward the wet-bulb temperature. For typical design condition of 95°F and 50 percent relative humidity for ambient air, the wet bulb temperature, based on psychrometric charts is 79°F. At 100 percent saturation the inlet cooling system would result in a 16°F decrease of the turbine inlet air.

While adiabatic cooling is most efficient for dry climates, adiabatic cooling in Florida can be an effective means of inlet air cooling during the late morning to evening hours. This period is typically 8 to 10 hours per day from about 10 am to 8 pm. In the early morning hours and evening hours, the typical relatively humidity in Florida is 70 to 90 percent depending on the climatic conditions. Because of the highly variable nature of ambient air conditions, the annual average inlet cooling was assumed to be 10°F. This average was reviewed against a 30 year record of meteorological data for Tampa and found to be representative of the range in conditions that occur over an annual period. This includes cooling associated with the typical mid-afternoon summer days and early morning/evening periods that occur year-round. The typical mid-afternoon cooling for Tampa would be 12°F and would occur in June with a mid-afternoon temperature of 90°F and 60 percent relative humidity. During January, the mid-afternoon cooling would be about 8°F. The typical cooling that would occur in the summer during early morning hours with temperatures of about 75°F and a relative humidity of 80 percent would be 4°F. This cooling also assumes that the gas stream can be 100 percent saturated. The average minimum temperatures for the months of November through April range from 49.5°F to 61.6°F with relative humidities ranging from 87 to 83 percent. The amount of adiabatic cooling would range from 1 to 2°F. The ambient air conditions that are modified by the fogging system occur naturally but are more frequent with the fogging system. The annual average temperature reduction assumed for on 24 hours operation is 10°F.

Turbine Performance and Emission Estimates

The effect of decreasing the turbine inlet air through the use of fogging will be to increase the mass flow of air that can go through the turbine which allows higher heat input and power output. The combustion turbine is also more efficient since the heat rate decreases with decreasing temperature. For the GE Model PG7111 (Frame 7EA) combustion turbine at the Larsen plant, a 10°F decrease in temperature for gas firing would result in a 3.3 percent increase in power and an associated 0.6 percent decrease in heat rate. Thus, while power increases, the production of power is more efficient with concomitant lower emissions per MW-hr generated. The increase in heat rate as a function of temperature decrease is a linear function and for the Larsen Unit 8 turbine would be 2.5 mmBtu/hr/°F when firing natural gas. The data were determined using GE supplied data (see Attachment A).

Because the turbine is operating on its original power curve, the emission characteristics do not change from what would normally occur at that temperature and relative humidity. An evaluation of emissions from the fogging tests conducted at several facilities in Florida did not result in any statistically significant differences in emission rates. The increase in emissions of criteria pollutants associated with fogging were determined using emission limits contained in the Title V Permit for the facility. This provides an estimate of the maximum potential emissions and would conservatively estimate annual increases in emission. Tables 1 and 2 presents a summary of the operating conditions and emission increases resulting from fogging when firing natural gas and distillate fuel oil, respectively.

The annual emissions were determined by multiplying the heat input increase per degree Fahrenheit (°F) times the emissions rate in lb/mmBtu for the number of °F-hours proposed for the turbine. The °F-hours/year is the total amount of annual temperature reduction proposed for fogging and was calculated by using the average temperature reduction multiplied by the hours of year assumed. For example, the °F-hours for gas firing are calculated by multiplying 8,760 hours times 10°F or 87,600°F-hours. The turbine inlet is equipped with temperature probes and will monitor the amount of inlet cooling. This reduction will be recorded for each hour of fogger operation. For Larsen Unit 8, a maximum of 58,400°F-hours of operation when firing natural gas and 29,200°F-hours of operation when firing distillate fuel oil was used as the basis for annual emission estimates for the turbine (see Tables 1 and 2).

Regulatory Applicability

A modification is defined in Rule 62-210.200 Florida Administrative Code (F.A.C.) as any physical change in, or a change in the method of operation of, or addition to a facility which would result in an increase in the actual emissions of any air pollutant subject to regulation under the Clean Air Act. A modification to a major source of air pollution, such as the Larsen Plant, may be subject to review under the Department's Prevention of Significant Deterioration (PSD) rules codified in Rule 62-212.400 F.A.C.

The proposed installation of direct water spray fogging system is a modification according to Rule 62-212.200 (188) F.A.C., since annual emissions will potentially increase as a result of the increased power and heat input. This has been confirmed by the Department in recent permitting actions.

Based on the available data, it is concluded that the emission rate does not change as a result of inlet fogging. Therefore, increase in annual potential emissions can be conservatively determined through the use of increases in heat input associated with the use of the fogging systems. For Larsen, the maximum potential annual increase in emissions is presented in Table 3.

These maximum potential emission rates are less than the significant emission rates in Table 62-212.400-2 in Rule 62-212.400 F.A.C. and, therefore, PSD would not apply. The pollutant closest to the PSD significant emission rates when firing natural gas is NO_x and is 13.2 tons per year (TPY) compared to the significant emission rate of 40 TPY. Emissions of SO_2 are 7.4 TPY and are primarily associated with distillate fuel oil, which is only used a backup to natural gas. Emission rates for CO and VOC on each fuel are similar in lb/mmBtu with maximum potential emissions less than 10 percent of the significant emission rates for those pollutants.

An amount of 87,600°F-hours provides a conservatively high basis for determing potential emissions from firing natural gas at 58,400°F-hours and distillate oil at 29,200°F-hours. Since natural gas is the primary fuel, with distillate oil backup, actual emission increases, assuming mostly gas firing, would be less than that shown in Table 3. As seen in Table 1, potential emissions at 8,760 hours operation on gas are less than those estimated with both fuels.

In addition, during periods when the fogging system is not used, the operation of the CTs will not be affected by this request and will be operated according to the Department's previous approvals (e.g., authorized to operated 8,760 hours/year/CT).

The inlet fogging system monitoring is proposed for a duration not to exceed 5 years as provided in Rule 62-210.200 (12) (d).

Table 1 Emission Estimates of the City of Lakeland Larsen Plant Unit 8 - Combustion Turbine with Inlet Air Cooling System with Direct Water Spray Inlet Fogging (Natural Gas Firing - 8,760 hours/year).

Performance Basis			
Temperature Decrease	°F (1)	10	
Power Increase		3.32%	Average of GE Data for Frame 7E
Heat Rate Decrease		-0.61%	Average of GE Data for Frame 7E
Heat Input Increase		2.49%	Average of Heat Input vs. Temperature
Heat Input Change	mmBtu/ °F	2.5	Average from 20 °F to 90 °F turbine inlet
Hours/year		8,760 (2)	
Hours-°F/year		87,600	hours/year times temperature decrease
Pollutants	**Units**	**Emissions**	**Comments**
PM	lb/MMBtu	0.0060	from Title V Application(3)
	TPY	0.65	
NO_x	lb/MMBtu	0.0995	from Title V Application(3)
	TPY	10.78	
SO_2	lb/MMBtu	0.0028	from Title V Application(3)
	TPY	0.31	
CO	lb/MMBtu	0.0550	from Title V Application(3)
	TPY	5.95	
VOC	lb/MMBtu	0.0018	from Title V Application(3)
	TPY	0.20	

Legend - TPY: tons per year

(1) Temperature decrease is average temperature differential of ambient temperature to compressor inlet temperature utilizing representative of average daytime conditions.

(2) Hours of fogger operation based on estimate of 24 hours per day and 365 days per year.

(3) Emission factor references - Title V Permit Application and Permit based on maximum hourly emissions and 25 °F turbine inlet conditions. PM = 0.006 lb/MMBtu; NO_X = 105 lb/hr x hr/1055 MMBtu = 0.0995 lb/MMBtu SO_2 = 3 lb/hr x hr/1055 MMBtu = 0.0028 lb/MMBtu; CO = 58 lb/hr x hr/1055 MMBtu = 0.0550 lb/MMBtu; VOC = 1.9 lb/hr x hr/1055 MMBtu = 0.0018 lb/MMBtu.

Example calculation for tons/year:

PM = 0.0060 lb/MMBtu x 2.5 MMBtu/°F x 10°F x 8,760 hours/year x ton/2,000 lb = 0.65 lb/MMBtu

NOTE: Calculation performed by computer spreadsheet which accounts for greater accuracy than calculating using rounded-off data in table.

Table 2 Emission Estimates of the City of Lakeland Larsen Plant Unit 8 - Combustion Turbine with Inlet Air Cooling System with Direct Water Spray Inlet Fogging (Distillate Oil Firing - 2,920 hours/year).

Performance Basis			
Temperature Decrease	°F (1)	10	
Power Increase		3.32%	Average of GE Data for Frame 7E
Heat Rate Decrease		-0.61%	Average of GE Data for Frame 7E
Heat Input Increase		2.49%	Average of Heat Input vs. Temperature
Heat Input Change	mmBtu/ °F	2.4	Average from 20 °F to 90 F turbine inlet
Hours/year		2,920 (2)	
Hours-°F/year		29,200	hours/year times temperature decrease
Pollutants	**Units**	**Emissions**	**Comments**
PM	lb/MMBtu	0.0250	from Title V Application(3)
	TPY	0.89	
NO_x	lb/MMBtu	0.1692	from Title V Application(3)
	TPY	6.02	
SO_2	lb/MMBtu	0.2029	from Title V Application(3)
	TPY	7.22	
CO	lb/MMBtu	0.0567	from Title V Application(3)
	TPY	2.02	
VOC	lb/MMBtu	0.0087	from Title V Application(3)
	TPY	0.31	

Legend - TPY: tons per year

(1) Temperature decrease is average temperature differential of ambient temperature to compressor inlet temperature utilizing representative of average daytime conditions.

(2) Hours of fogger operation based on limit of 2,920 hours per year.

(3) Emission factor references - Title V Permit Application and Permit based on maximum hourly emissions and 25 °F turbine inlet conditions. PM = 26 lb/hr x hr/1,040 MMBtu = 0.0250 lb/MMBtu; NO_X = 176 lb/hr x hr/1,040 MMBtu = 0.1692 lb/MMBtu; SO_2 = 211 lb/hr x hr/1,040 MMBtu = 0.2029 lb/MMBtu; CO = 59 lb/hr x hr/1,040 MMBtu = 0.0567 lb/MMBtu; VOC = 9 lb/hr x hr/1,040 MMBtu = 0.0087 lb/MMBtu

Table 3 Maximum Annual Emissions of the City of Lakeland Larsen Plant Unit 8 - Combustion Turbine with Inlet Air Cooling System with Direct Water Spray Inlet Fogging (Natural Gas Firing - 5,840 hours/year and Oil Firing 2,920 hours/year).

	Annual Emissions (tons/year)			PSD SERs[1]
Pollutants	Gas Firing	Oil Firing	Total	(tons/year)
PM	0.43	0.89	1.32	15 & 25[2]
NO_x	7.19	6.02	13.21	40
SO_2	0.21	7.22	7.43	40
CO	3.97	2.02	5.99	100
VOC	0.13	0.31	0.44	40

(1) PSD = Prevention of Significant Deterioration; SERs - Significant Emission Rates; Rule 62-212.400(2)(e)2.
(2) 15 tons/year is for PM10 and 25 tons/year is for PM.

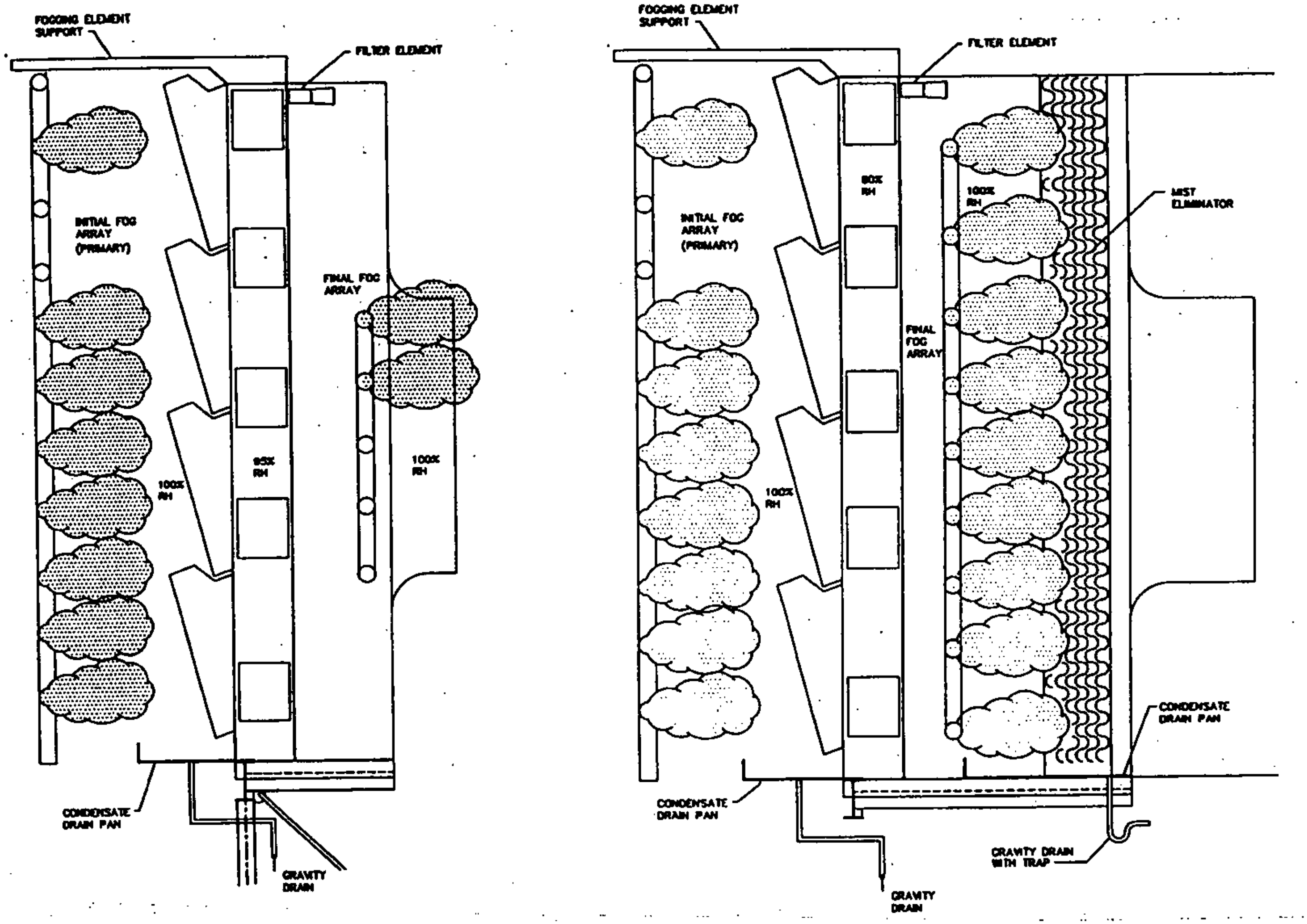

Figure 1. Illustrative Fogging System Schematic

Source: Caldwell Energy and Environmental, Inc. 1999.

Golder Associates

ATTACHMENT A

TURBINE PERFORMANCE DATA

Table A-1. Combustion Turbine Performance Data - General Electric Model PG7111(EA) Gas Turbine Firing Natural Gas

Temp. (oF)	Heat Input (mmBtu/hr)	Increase (mmBtu/hr)	Increase (%)	Average mmBtu/hr per oF	Capacity (MW)	Increase (MW)	Increase (%)	Average Increase(MW) per oF	Heat Rate (Btu/kWhr)	Decrease (Btu/kWhr)	Decrease (%)	Average Decrease per oF
90	890				80.278				10,659			
70	940	50	5.62%	2.50	86.592	6.314	7.87%	0.32	10,555	-104.50	-0.98%	-5.23
59	965	25	2.66%	2.27	90.2	3.608	4.17%	0.33	10,450	-104.50	-0.99%	-9.50
40	1010	45	4.66%	2.37	95.612	5.412	6.00%	0.28	10,346	-104.50	-1.00%	-5.50
20	1065	55	5.45%	2.75	101.926	6.314	6.60%	0.32	10,241	-104.50	-1.01%	-5.23
Average:	995.00	43.75	4.60%	2.47	93.5825	5.412	6.16%	0.31	10,398	-104.50	-1.00%	-6.36

Source: GE, 1988 and 1989.

Table A-2. Combustion Turbine Performance Data - General Electric Model PG7111(EA) Gas Turbine Firing Distillate Oil

Temp. (oF)	Heat Input (mmBtu/hr)	Increase (mmBtu/hr)	Increase (%)	Average mmBtu/hr per oF	Capacity (MW)	Increase (MW)	Increase (%)	Average Increase(MW) per oF	Heat Rate (Btu/kWhr)	Decrease (Btu/kWhr)	Decrease (%)	Average decrease per oF
90	875				78.96				10,730			
70	925	50	5.71%	2.50	85.17	6.2104	7.87%	0.31	10,625	-105.20	-0.98%	-5.26
59	946	21	2.27%	1.91	88.72	3.5488	4.17%	0.32	10,520	-105.20	-0.99%	-9.56
40	1000	54	5.71%	2.84	94.04	5.3232	6.00%	0.28	10,415	-105.20	-1.00%	-5.54
20	1050	50	5.00%	2.50	100.25	6.2104	6.60%	0.31	10,310	-105.20	-1.01%	-5.26
Average:	980.25	43.75	4.67%	2.44	92.047	5.3232	6.16%	0.31	10,467	-105.20	-1.00%	-6.41

Source: GE, 1988 and 1989.

ATTACHMENT B

TITLE V SPECIFIC CONDITIONS

FOR LARSEN UNIT 8

Section III. Emissions Unit(s) and Conditions.

Subsection D. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
-008	Combined Cycle Combustion Turbine

The emission unit is a 120 megawatt combined cycle combustion gas turbine with a heat recovery steam generator (HRSG) designated as Larsen Unit #8. The combustion turbine fires natural gas as the primary fuel, and No. 2 distillate oil with a maximum sulfur content of 0.20 percent by weight as a limited auxiliary fuel. The combustion turbine is a GE Model PG7111 (EA) Frame 7 unit equipped with water injection to reduce nitrogen oxides emissions. The HRSG powers an existing steam turbine. The emissions unit can exhaust through the HRSG or through a by-pass stack. Turbine #8 began commercial service in July, 1992.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; 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.; Prevention of Significant Deterioration (PSD) in Rule 62-212.400, F.A.C.; and Best Available Control Technology (BACT), dated July 26, 1991, in Rule 62-212.410, F.A.C.}

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

Essential Potential to Emit (PTE) Parameters

D.1. Permitted Capacity. The maximum process/operation rate, at an inlet temperature of 25 degrees F, is 1055 MMBtu per hour (lower heating value) heat input firing natural gas or 1040 MMBtu per hour (lower heating value) heat input firing No. 2 distillate oil.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

D.2. Methods of Operation. Fuels.
a. This emissions unit fires natural gas as the primary fuel and No. 2 distillate oil as the secondary fuel.
b. The consumption of No. 2 distillate oil shall not exceed 8,190 gallons per hour and 23,914,800 gallons per year.
c. The maximum annual firing of No. 2 distillate oil shall not exceed 1/3 of the annual capacity factor.
d. The maximum sulfur content of the No. 2 distillate oil shall not exceed 0.20 percent by weight.
[Rules 62-210.200(PTE), 62-212.400, and 62-212.410, F.A.C.; and, PSD-FL-166]

D.3. 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.}

D.4. Nitrogen Oxides. The NO_X emissions shall not exceed 25 ppmv at 15 percent oxygen on a dry basis and 425 tons per year when firing natural gas.
[Rule 62-212.400(6), F.A.C.; and, PSD-FL-166]

D.5. Nitrogen Oxides. The NO_X emissions shall not exceed 42 ppmv at 15 percent oxygen on a dry basis and 244 tons per year when firing No. 2 distillate oil.
[Rule 62-212.400(6), F.A.C.; and, PSD-FL-166]

{Permitting note: Since the BACT limit established for nitrogen oxides is more stringent than the NSPS limit, compliance with the nitrogen oxides BACT limits of specific conditions **D4.** and **D.5.** is assumed to show compliance with the nitrogen oxides limit of 40 CFR 60.332.}

D.6. Sulfur Dioxide. The SO_2 emissions shall not exceed 8.6 tons per year when firing natural gas.
[Rule 62-212.400(6), F.A.C.; and, PSD-FL-166]

D.7. Sulfur Dioxide. The SO_2 emissions shall not exceed 307 tons per year when firing No. 2 distillate oil. The maximum sulfur content of the No. 2 distillate oil shall not exceed 0.20 percent by weight.
[Rule 62-212.400(6), F.A.C.; and, PSD-FL-166]

D.8. PM/PM_{10}. The PM/PM_{10} emissions shall not exceed 0.006 pound per MMBtu heat input and 22 tons per year when firing natural gas.
[Rule 62-212.400(6), F.A.C.; and, PSD-FL-166]

D.9. PM/PM_{10}. The PM/PM_{10} emissions shall not exceed 0.025 pound per MMBtu heat input and 22 tons per year when firing No. 2 distillate oil.
[Rule 62-212.400(6), F.A.C.; and, PSD-FL-166]

D.10. Sulfuric Acid Mist. The sulfuric acid mist emissions shall not exceed 0.8 ton per year when firing natural gas.
[Rule 62-212.400(6), F.A.C.; and, PSD-FL-166]

D.11. Sulfuric Acid Mist. The sulfuric acid mist emissions shall not exceed 9.13 ton per year when firing No. 2 distillate oil. The maximum sulfur content of the No. 2 distillate oil shall not exceed 0.20 percent by weight.
[Rule 62-212.400(6), F.A.C.; and, PSD-FL-166]

D.12. Visible Emissions. Visible emissions shall not exceed 10 percent opacity.
[Requested in initial Title V permit application dated June 14, 1996; and, AC 53-190437 and PSD-FL-166]

D.13. Volatile Organic Compounds. Volatile Organic Compounds emissions shall not exceed 9 tons per year when firing natural gas or 22 tons per year when firing oil.
[AC 53-190437 and PSD-FL-166]

D.14. Carbon Monoxide. Carbon Monoxide emissions shall not exceed 25 ppmv at 15 percent oxygen on a dry basis and 232 tons per year when firing natural gas or 79 tons per year when firing oil.
[AC 53-190437 and PSD-FL-166]

D.15. Mercury. Mercury emissions shall not exceed 3.0×10^{-6} pounds per million Btu heat input and 0.003 ton per year when firing oil.
[AC 53-190437 and PSD-FL-166]

D.16. Lead. Lead emissions shall not exceed 2.8×10^{-5} pounds per million Btu heat input and 0.03 ton per year when firing oil.
[AC 53-190437 and PSD-FL-166]

D.17. Beryllium. Beryllium emissions shall not exceed 2.5×10^{-6} pounds per million Btu heat input and 0.003 ton per year when firing oil.
[AC 53-190437 and PSD-FL-166]

Excess Emissions

D.18. 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.]

D.19. 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

D.20. 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)]

D.21. The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG and using water injection to control NO_X emissions shall operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within $\pm$5.0 percent and shall be approved by the Administrator.
[40 CFR 60.334(a)]

D.22. 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)]

{Permitting note: **No. 2 distillate oil is only supplied with intermediate bulk storage; and, a custom fuel schedule has been established for natural gas.**}

D.23. This emissions unit is also subject to the conditions contained in **Subsection E. Common Conditions.**

D.24. The permittee shall monitor sulfur content and nitrogen content of natural gas fired in the turbine as follows:

<u>Custom Fuel Monitoring Schedule for Natural Gas</u>

1. Monitoring of fuel nitrogen content shall not be required when firing natural gas.

2. Sulfur Monitoring:
   a. Analysis for fuel sulfur content of the natural gas shall be conducted using one of the EPA approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. The reference methods are ASTM D1072-90(94)E-1; ASTM D3031-81(86); ASTM D3246-92; and ASTM D4084-94 as referenced in 40 CFR 60.335(b)(2).
   b. Sulfur monitoring shall be conducted once per quarter for six quarters, beginning on July 1, 1996.
   c. If the sulfur monitoring required for natural gas by 2(b) above shows little variability and the calculated sulfur dioxide emissions represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample analysis shall be conducted twice per year. This monitoring shall be conducted during the first and third quarters of each calendar year.
   d. Should any sulfur analysis as required by items 2(b) or 2(c) above indicate noncompliance with 40 CFR 60.333 the City will notify the Department of Environmental Protection of such excess emission and the customized fuel monitoring schedule shall be re-examined.

3. The City will notify the Department of Environmental Protection of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content varying greater than 10 grains/1000 cf gas) shall be considered as a change in natural gas supply. Sulfur content of the natural gas will be monitored weekly during the interim period when this monitoring schedule is being reexamined.

4. Records of sampling analysis and natural gas supply pertinent to this monitoring schedule shall be retained by the City for a period of five (5) years, and shall be available for inspection by appropriate regulatory personnel.

5. The City will obtain the sulfur content of the natural gas from Florida Gas Transmission Company.
[40 CFR 60.334(b)(2); Rule 62-213.400, F.A.C.; and, AC 53-190437 and PSD-FL-166]

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.25. 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)]

D.26. When determining compliance with 40 CFR 60.332, Subpart GG - Standards of Performance for Stationary Gas Turbines, the monitoring device of 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with the permitted NO_X standard at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.
[40 CFR 60.335(c)(2)]

D.27. 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)]

D.28. Initial compliance with the nitrogen oxides limit pursuant to 40 CFR 60.8 was conducted August 3-7, 1992. For annual compliance purposes, compliance with the nitrogen oxides limits of specific conditions **D.4.** and **D.5.** will be determined using EPA Method 20 and testing at capacity as defined by specific condition **D.36.** Correction to ISO conditions is not required for these annual compliance tests.
[Rule 62-297.310, F.A.C.]

D.29. The owner or operator shall determine compliance with the sulfur content standard of 0.20 percent, by weight, as follows: ASTM D 2880-96 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-90(94)E-1, D 3031-81(86), D 4084-94, or D 3246-92 shall be used for the sulfur content of gaseous fuels (incorporated by reference-see 40 CFR 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.
[40 CFR 60.335(d)]

D.30. 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.
[40 CFR 60.335(e)]

D.31. PM/PM_{10}. The test methods for PM/PM_{10} emissions when firing oil shall be EPA Methods 5, 5B or 17, incorporated by reference in Chapter 62-297, F.A.C. The opacity emissions test may be used unless 10% opacity is exceeded.
[Rules 62-213.440, 62-297.310, and 62-297.401, F.A.C.; and, PSD-FL-166]

D.32. Sulfuric Acid Mist. Compliance with the sulfuric acid mist standard shall be demonstrated by using natural gas or 0.2 percent sulfur, by weight, No. 2 distillate oil.
[Rules 62-213.440, 62-297.310, and 62-297.401, F.A.C.; and, PSD-FL-166]

D.33. Visible Emissions. The test method for visible emissions shall be EPA Method 9, incorporated by reference in Chapter 62-297, F.A.C.
[Rules 62-213.440, 62-297.310, and 62-297.401, F.A.C.; and, PSD-FL-166]

D.34. Volatile Organic Compounds, Carbon Monoxide, Mercury, Lead and Beryllium. The initial compliance test requirement for these pollutants has been satisfied and no further tests are required.
[AC 53-190437 and PSD-FL-166]

D.35. Frequency of Compliance Tests. General Compliance Testing. 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.
[Rule 62-297.310(7)(a)8., F.A.C.]

D.36. Operating Rate During Testing. **Not federally enforceable.** Testing of emissions shall be conducted with the source operating at capacity. Capacity is defined as 95-100 percent of the manufacturer's rated heat input achievable for the average ambient (or conditioned) air temperature during the test. If it is impracticable to test at capacity, then sources may be tested at less than capacity. In such cases, the entire heat input vs. inlet temperature curve will be adjusted by the increment equal to the difference between the design heat input value and 105 percent of the value reached during the test. Data, curves, and calculations necessary to demonstrate the heat input rate correction at both design and test conditions shall be submitted to the Department with the compliance test report. When testing shows that NO_X emissions exceed the standard when operating at capacity, the permittee shall recalibrate the NO_X emission control system using emission testing at four loads as required in Subpart GG.
[Requested in a letter dated February 7, 1997.]

D.37. This emissions unit is also subject to the conditions contained in **Subsection E. Common Conditions.**

Record Keeping and Reporting Requirements

D.38. For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:
a. *Nitrogen oxides*. Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-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 water-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)]

D.39. 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)]

D.40. 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)]

D.41. This emissions unit is also subject to the conditions contained in **Subsection E. Common Conditions.**

<u>Miscellaneous Requirements.</u>

D.42. Unless the Department has determined that other ambient concentrations are required to protect the public health and safety, predicted ambient air concentrations (AAC) shall not exceed the following levels for the pollutants shown:

	Florida Air Reference Concentrations (ug/cubic meter)		
Pollutant	8 hr. avg.	24 hr. avg.	Annual avg.
Beryllium	0.02	0.005	0.0004
Lead	1.5	0.36	0.09
Inorganic mercury compounds, all forms of vapor, as Hg	---	---	0.3

[AC 53-190437 and PSD-FL-166]

D.43. <u>Definitions</u>. 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.44. 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]