PERMIT APPLICATION FOR
CITY OF LAKELAND
DEPARTMENT OF ELECTRIC UTILITIES
C.D. MCINTOSH, JR. POWER PLANT

Prepared For:
Lakeland Electric
501 East Lemon Street
Lakeland, FL 33801-5079

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

April 2000
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5 Copies – Lakeland Electric
2 Copies – Golder Associates Inc.

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: **C.D. McIntosh, Jr. Power Plant.**	
3. Facility Identification Number: **1050004** [ ] Unknown	
4. Facility Location: Street Address or Other Locator: **3030 East Lake Parker Drive** City: **Lakeland** County: **Polk** Zip Code: **33805**	
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 East Lemon Street** City: **Lakeland** State: **FL** Zip Code: **33801-5079**
3. Application Contact Telephone Numbers: Telephone: (**941**) **834 – 6300** Fax: (**941**) **834 - 6344**

Application Processing Information (DEP Use)

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

Purpose of Application

Air Operation Permit Application

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

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

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

Current construction permit number:______________________

[X] 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: **1050004-004-AC**

Operation permit number to be revised: **1050004-003-AV**

[ ] 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)

[ ] 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: **(941) 834 - 6300** Fax: **(941) 834 - 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 W. Tomlin — 4-21-00 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 [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.

Bernard F. Kosky — April 19, 2000

Signature — Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
028	McIntosh Unit 5; W501G Combustion Turbine	AF2A	
029	Unregulated Emissions	AC1C	

Application Processing Fee

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

Construction/Modification Information

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

Application Comment

This application is a revision to the final Title V permit issued to the C.D. McIntosh Power Plant to incorporate Unit 5 (simple cycle) and an associated distillate oil storage tank.

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates: Zone: **17** East (km): **409.0** North (km): **3106.2**			
2. Facility Latitude/Longitude: Latitude (DD/MM/SS): **26 / 4 / 50** Longitude (DD/MM/SS): **81 / 55 / 32**			
3. Governmental Facility Code: **4**	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 McIntosh Power Plant consists of 3 fossil fuel fired-steam generators (FFFSG), 2 diesel powered generators, and 1 gas turbine. FFFSG Units 1 and 2 are fired with No. 6 fuel oil and natural gas (distillate oil is used as an ignitor). FFFSG Unit 3 is primarily fired with coal, refuse derived fuel and petroleum coke. This application is for inclusion of Unit 5 into the Title V permit for the facility.**			

Facility Contact

1. Name and Title of Facility Contact: **Ms. Farzie Shelton, Manager of 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: (**941**) **834 – 6603**	Fax: (**941**) **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. [X] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [ ] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters): **Unit 5 is subject to NSPS Subpart GG. The tank is subject to subpart Kb.**	

List of Applicable Regulations

The facility regulations identified in the Title V permit (Final Permit No. 10150004-003-AV)	
will not change as a result of this application.	

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): [ ] Attached, Document ID: ________ [X] 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: [ ] Attached, Document ID: ____________ [X] Not Applicable	
7. Supplemental Requirements Comment: **Area map and facility plot plan submitted with Title V application.**	

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

[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):

McIntosh Unit 5

4. Emissions Unit Identification Number: [ ] No ID
ID: **028** [ ] ID Unknown

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

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

This emission unit is a Westinghouse 501G combustion turbine operating in a simple cycle.

Emissions Unit Control Equipment

1. Control Equipment/Method Description (Limit to 200 characters per device or method): **Dry Low NO_X combustion – Natural gas firing** **Water injection – distillate oil firing**	
2. Control Device or Method Code(s): **25, 28**	

Emissions Unit Details

1. Package Unit: Manufacturer: **Westinghouse**	Model Number: **501G**	
2. Generator Nameplate Rating:	**249** MW	
3. Incinerator Information:		
Dwell Temperature:		°F
Dwell Time:		seconds
Incinerator Afterburner Temperature:		°F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:			2,174	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	8,760	hours/year
6. Operating Capacity/Schedule Comment (limit to 200 characters): **Maximum heat input at ISO conditions and natural gas firing (LHV) maximum for oil firing is 2,236 mmBtu/hr (ISO-LHV). Heat input a function of turbine inlet temperature.**				

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment LMC-EU1-C for operational requirements

ATTACHMENT LMC-EU1-C

Applicable Requirements Listing

EMISSION UNIT ID: EU1 – McIntosh Plant

FDEP Rules:

Air Pollution Control-General Provisions:

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

Stationary Sources-General:

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

Acid Rain:

62-214.300	All Acid Rain Units (Applicability)
62-214.320(1)(a),(2)	All Acid Rain Units (Application Shield)
62-214.330(1)(a)1.	Compliance Options (if 214.430)
62-214.340	Exemptions (new units, retired units)
62-214.350(2);(3);(6)	All Acid Rain Units (Certification)
62-214.370	All Acid Rain Units

(Revisions; correction; potentially applicable if a need arises)

62-214.430	All Acid Rain Units (Compliance Options-if required)

Stationary Sources-Emission Standards

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

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

62-297.310(1)	All Units (Test Runs-Mass Emission)
62-297.310(2)(b)	All Units (Operating Rate; other than CTs; no CT)
62-297.310(3)	All Units (Calculation of Emission)
62-297.310(4)(a)	All Units (Applicable Test Procedures; Sampling time)
62-297.310(4)(b)	All Units (Sample Volume)
62-297.310(4)(c)	All Units (Required Flow Rate Range-PM/H_2SO_4/F)
62-297.310(4)(d)	All Units (Calibration)
62-297.310(4)(e)	All Units (EPA Method 5-only)
62-297.310(5)	All Units (Determination of Process Variable)
62-297.310(6)(a)	All Units (Permanent Test Facilities-general)
62-297.310(6)(c)	All Units (Sampling Ports)
62-297.310(6)(d)	All Units (Work Platforms)

62-297.310(6)(e)	All Units (Access)
62-297.310(6)(f)	All Units (Electrical Power)
62-297.310(6)(g)	All Units (Equipment Support)
62-297.310(7)(a)1.	Applies mainly to CTs/Diesels
62-297.310(7)(a)2.	FFSG excess emissions
62-297.310(7)(a)3.	Permit Renewal Test Required
62-297.310(7)(a)4.a.	Annual Test
62-297.310(7)(a)5.	PM exemption if < 400 hrs/yr
62-297.310(7)(a)6.	PM FFSG semi annual test required if > 200 hrs/yr
62-297.310(7)(a)7.	PM quarterly monitoring if > 100hrs/yr
62-297.310(7)(a)9.	FDEP Notification – 15 days
62-297.310(7)(c)	Waiver of Compliance Tests (Fuel Sampling)
62-297.310(8)	Test Reports

Federal Rules:

NSPS Subpart GG:

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

NSPS General Requirements:

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

Acid Rain-Permits:

40 CFR 72.9(a)	Permit Requirements
40 CFR 72.9(b)	Monitoring Requirements
40 CFR 72.9(c)(1)	SO_2 Allowances-hold allowances
40 CFR 72.9(c)(2)	SO_2 Allowances-violation
40 CFR 72.9(c)(3)(iii)	SO_2 Allowances-Phase II Units (listed)
40 CFR 72.9(c)(4)	SO_2 Allowances-allowances held in ATS
40 CFR 72.9(c)(5)	SO_2 Allowances-no deduction for 72.9(c)(1)(i)
40 CFR 72.9(d)	NO_X Requirements
40 CFR 72.9(e)	Excess Emission Requirements
40 CFR 72.9(f)	Recordkeeping and Reporting
40 CFR 72.9(g)	Liability
40 CFR 72.20(a)	Designated Representative; required
40 CFR 72.20(b)	Designated Representative; legally binding
40 CFR 72.20(c)	Designated Representative; certification requirements
40 CFR 72.21	Submissions
40 CFR 72.22	Alternate Designated Representative
40 CFR 72.23	Changing representatives; owners
40 CFR 72.24	Certificate of representation
40 CFR 72.30(a)	Requirements to Apply (operate)
40 CFR 72.30(b)(2)	Requirements to Apply (Phase II-Complete)
40 CFR 72.30(c)	Requirements to Apply (reapply before expiration)
40 CFR 72.30(d)	Requirements to Apply (submittal requirements)
40 CFR 72.31	Information Requirements; Acid Rain Applications
40 CFR 72.32	Permit Application Shield
40 CFR 72.33(b)	Dispatch System ID; unit/system ID
40 CFR 72.33(c)	Dispatch System ID; ID requirements
40 CFR 72.33(d)	Dispatch System ID; ID change
40 CFR 72.40(a)	General; compliance plan
40 CFR 72.40(b)	General; multi-unit compliance options
40 CFR 72.40(c)	General; condition approval
40 CFR 72.40(d)	General; termination of compliance options
40 CFR 72.51	Permit Shield
40 CFR 72.90	Annual Compliance Certification

Allowances:

40 CFR 73.33(a),(c)	Authorized account representative
40 CFR 73.35(c)(1)	Compliance: ID of allowances by serial number

Monitoring Part 75:

40 CFR 75.4	Compliance Dates;
40 CFR 75.5	Prohibitions
40 CFR 75.10(a)(1)	Primary Measurement; SO_2
40 CFR 75.10(a)(2)	Primary Measurement; NO_X
40 CFR 75.10(a)(3)(iii)	Primary Measurement; CO_2; O_2 monitor
40 CFR 75.10(b)	Primary Measurement; Performance Requirements
40 CFR 75.10(c)	Primary Measurement; Heat Input; Appendix F
40 CFR 75.10(e)	Primary Measurement; Optional Backup Monitor
40 CFR 75.10(f)	Primary Measurement; Minimum Measurement
40 CFR 75.10(g)	Primary Measurement; Minimum Recording
40 CFR 75.11(d)	SO_2 Monitoring; Gas- and Oil fired units

40 CFR 75.11(e)	SO_2 Monitoring; Gaseous firing
40 CFR 75.12(a)	NO_x Monitoring; Coal; Non-peaking oil/gas units
40 CFR 75.12(b)	NO_x Monitoring; Determination of NOX emission rate; Appendix F
40 CFR 75.13(b)	CO_2 Monitoring; Appendix G
40 CFR 75.13(c)	CO_2 Monitoring; Appendix F
40 CFR 75.14(c)	Opacity Monitoring; Gas units; exemption
40 CFR 75.20(a)	Initial Certification Approval Process; Loss of Certification
40 CFR 75.20(b)	Recertification Procedures (if recertification necessary)
40 CFR 75.20(c)	Certification Procedures (if recertification necessary)
40 CFR 75.20(d)	Recertification Backup/portable monitor
40 CFR 75.20(f)	Alternate Monitoring system
40 CFR 75.21(a)	QA/QC; CEMS; Appendix B (Suspended 7/17/95-12/31/96)
40 CFR 75.21(c)	QA/QC; Calibration Gases
40 CFR 75.21(d)	QA/QC; Notification of RATA
40 CFR 75.21(e)	QA/QC; Audits
40 CFR 75.21(f)	QA/QC; CEMS (Effective 7/17/96-12/31/96)
40 CFR 75.22	Reference Methods
40 CFR 75.24	Out-of-Control Periods; CEMS
40 CFR 75.30(a)(3)	General Missing Data Procedures; NO_X
40 CFR 75.30(a)(4)	General Missing Data Procedures; SO_2
40 CFR 75.30(b)	General Missing Data Procedures; certified backup monitor
40 CFR 75.30(c)	General Missing Data Procedures; certified backup monitor
40 CFR 75.30(d)	General Missing Data Procedures; SO_2 (optional before 1/1/97)
40 CFR 75.30(e)	General Missing Data Procedures; bypass/multiple stacks
40 CFR 75.31	Initial Missing Data Procedures (new/re-certified CMS)
40 CFR 75.32	Monitoring Data Availability for Missing Data
40 CFR 75.33	Standard Missing Data Procedures
40 CFR 75.36	Missing Data for Heat Input
40 CFR 75.40	Alternate Monitoring Systems-General
40 CFR 75.41	Alternate Monitoring Systems-Precision Criteria
40 CFR 75.42	Alternate Monitoring Systems-Reliability Criteria
40 CFR 75.43	Alternate Monitoring Systems-Accessibility Criteria
40 CFR 75.44	Alternate Monitoring Systems-Timeliness Criteria
40 CFR 75.45	Alternate Monitoring Systems-Daily QA
40 CFR 75.46	Alternate Monitoring Systems-Missing data
40 CFR 75.47	Alternate Monitoring Systems-Criteria for Class
40 CFR 75.48	Alternate Monitoring Systems-Petition
40 CFR 75.53	Monitoring Plan; revisions
40 CFR 75.54(a)	Recordkeeping-general
40 CFR 75.54(b)	Recordkeeping-operating parameter
40 CFR 75.54(c)	Recordkeeping-SO_2
40 CFR 75.54(d)	Recordkeeping-NO_X
40 CFR 75.54(e)	Recordkeeping-CO_2
40 CFR 75.54(f)	Recordkeeping-Opacity
40 CFR 75.55(c)	General Recordkeeping (Specific Situations)
40 CFR 75.55(e)	General Recordkeeping (Specific Situations)
40 CFR 75.56	Certification; QA/QC Provisions
40 CFR 75.60	Reporting Requirements-General
40 CFR 75.61	Reporting Requirements-Notification cert/recertification

40 CFR 75.62	Reporting Requirements-Monitoring Plan
40 CFR 75.63	Reporting Requirements-Certification/Recertification
40 CFR 75.64(a)	Reporting Requirements-Quarterly reports; submission
40 CFR 75.64(b)	Reporting Requirements-Quarterly reports; DR statement
40 CFR 75.64(c)	Rep. Req.; Quarterly reports; Compliance Certification
40 CFR 75.64(d)	Rep. Req.; Quarterly reports; Electronic format
40 CFR 75.66	Petitions to the Administrator (if required)
Appendix A-1	Installation and Measurement Locations
Appendix A-2	Equipment Specifications
Appendix A-3	Performance Specifications
Appendix A-4	Data Handling and Acquisition Systems
Appendix A-5	Calibration Gases
Appendix A-6	Certification Tests and Procedures
Appendix A-7	Calculations
Appendix B	QA/QC Procedures
Appendix C-1	Missing Data; SO_2/NO_X for controlled sources
Appendix C-2	Missing Data; Load-Based Procedure; NO_X & flow
Appendix D	Optional SO_2; Oil-/gas-fired units
Appendix F	Conversion Procedures
Appendix H	Traceability Protocol

Acid Rain Program-Excess Emissions (these are future requirements):

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

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **N/A**	2. Emission Point Type Code: **1**
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): **Exhausts through a single stack.**	
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:	

5. Discharge Type Code: **V**	6. Stack Height: **85** feet	7. Exit Diameter: **28** feet
8. Exit Temperature: **1,095** °F	9. Actual Volumetric Flow Rate: **3,055,750** acfm	10. Water Vapor: **12.44** %

11. Maximum Dry Standard Flow Rate: **894,739** dscfm	12. Nonstack Emission Point Height: feet
13. Emission Point UTM Coordinates: Zone: **17** East (km): **408.79** North (km): **3106.66**	
14. Emission Point Comment (limit to 200 characters): **Stack parameters for ISO operating condition firing natural gas; for oil 1,051°F and 3,011,513 ACFM.**	

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

Segment Description and Rate: Segment 1 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Distillate (No. 2) Fuel Oil**		
2. Source Classification Code (SCC): **2-01-001-01**	3. SCC Units: **1,000 gallons**	
4. Maximum Hourly Rate: **17.8**	5. Maximum Annual Rate: **4,251**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.05**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **132**
10. Segment Comment (limit to 200 characters): **mmBtu/SCC = 131.5 (rounded to 132). BASIS: Max. hourly = 30°F turbine inlet & 7.1 lb/gal; 18,500 Btu/lb LHV; Annual: 59°F, 250 hrs/yr operation. Max hourly; function of turbine inlet temp.**		

Segment Description and Rate: Segment 2 of 2

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **2-01-002-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **2.427**	5. Maximum Annual Rate: **16,462**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters): **Max. based on 30°F; 950 Btu/CF LHV. Annual based on 59°F; 7,008 hrs/yr operation. Max. hourly a function of turbine inlet temperature.**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			EL
SO_2			EL
NO_X	026	028	EL
CO			EL
VOC			EL
PM_{10}			EL

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **139.6** lb/hour **49** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **PSD-FL-245**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Tons/year (8,510 hours gas x 8.8 lb/hr + 250 hours oil x 92.8 lb/hour) / 2000 hours/year = 49.0 Tons/Year.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, 50% load, 30°F; tons/year based on 8,510 hours/yr gas firing and 250 hrs/yr oil firing; 59°F conditions.**	

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: **10% opacity**	4. Equivalent Allowable Emissions: **139.6** lb/hour **11.6** tons/year
5. Method of Compliance (limit to 60 characters): **Annual VE test; EPA Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - 30°F; 50% load; annual based on 59°F; 100% load, 250 hrs/yr.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

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: **10% opacity**	4. Equivalent Allowable Emissions: **9.1** lb/hour **38.5** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test; EPA Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing - 30°F, 100% load; annual based on 59°F; 100% load, 8,760 hrs/yr.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **127** lb/hour **46.5** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **See Comment** Reference: **PSD-FL-245**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Tons/year = (8,150 hours-gas x 7.2 lb/hr + 250 hours-oil x 127 lb/hour) / 2000 lb/ton = 46.5.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emission Factor: 1 grain S per 100 CF gas; 0.05% S oil. lb/hr based on oil firing. Tons/yr based on 8,510 hrs/yr gas firing and 250 hrs/yr oil firing.**	

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: **0.05% Sulfur Oil**	4. Equivalent Allowable Emissions: **127** lb/hour **15.9** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; annual based on 250 hrs/yr.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

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: **1 grain/100 CF**	4. Equivalent Allowable Emissions: **7.2** lb/hour **31.5** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Sampling**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing – annual based on 8,760 hrs/yr.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_X**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **433** lb/hour **1,060** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **PSD-FL-245**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Tons/year = (8,510 hours-gas x 237 lb/hr + 250 hours-oil x 413 lb/hr) / 2,000 lb/ton = 1,060 tons/year.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, 100% load, 30°F; tons/yr based on 8,510 hrs/yr gas firing and 250 hrs/yr oil firing; 59°F conditions.**	

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: **413 lb/hr (3hr-avg)**	4. Equivalent Allowable Emissions: **431** lb/hour **51.6** tons/year
5. Method of Compliance (limit to 60 characters): **CEM-30 Day Rolling Average (corrected to 15% Oxygen)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; 30°F; 100% load; annual based on 250 hrs/year at 59°F (413 lb/hour).**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **NO_X**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

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: **237 lb/hr (24hr-avg)**	4. Equivalent Allowable Emissions: **249** lb/hour **1,038** tons/year
5. Method of Compliance (limit to 60 characters): **CEM 24 hour block average**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 30°F; 100% load, annual based on 8,760 hr/yr at 59°F (237 lb/hr); see Attachment LMC-EU1-J13; Section 2.0; Appendix A.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **568** lb/hour **684.4** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **PSD-FL-245**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Tons/year = (8,510 hours-gas x 145 lb/hour + 250 hours-oil x 539 lb/hour) / 2,000 lb/ton = 684.4.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing; 30°F tons/yr based on 8,510 hrs/yr gas firing and 250 hrs/yr oil firing; 59°F conditions.**	

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: **90 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **568** lb/hour **67.4** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; annual compliance test > 400 hours/year**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; 30°F; annual based on 250 hrs/yr at 59°F and 100% load, 539 lb/hr.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **CO**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

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: **25 ppmvd @ 15% O_2**	4. Equivalent Allowable Emissions: **153** lb/hour **635** tons/year
5. Method of Compliance (limit to 60 characters): **EPA Method 10; annual compliance test**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; 30°F; annual based on 8,760 hrs/yr at 59°F 100% load, 145 lb/hr.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **25** lb/hour **45.7** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **PSD-FL-245**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Tons/year = (8,510 hours-gas x 10 lb/hr + 250 hours-oil x 25 lb/hr) / 2,000 lb/ton = 45.7)**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing. Tons/yr based on 8,510 hrs/yr gas firing and 250 hrs/yr oil firing.**	

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: **10 ppmvd**	4. Equivalent Allowable Emissions: **25** lb/hour **3.1** tons/year
5. Method of Compliance (limit to 60 characters): **Meeting CO emission limit**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing; annual based on 250 hrs/yr.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **VOC**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

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: **4 ppmvd**	4. Equivalent Allowable Emissions: **10** lb/hour **43.8** tons/year
5. Method of Compliance (limit to 60 characters): **Meeting CO emission limit**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing; annual based on 8,760 hrs/yr.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **139.6** lb/hour **49** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: **PSD-FL-245**	7. Emissions Method Code: **2**
8. Calculation of Emissions (limit to 600 characters): **Tons/year (8,510 hours-gas x 8.8 lb/hr + 250 hours oil x 92.8 lb/hour) / 2,000 hours/year = 49.0 tons/year.**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr based on oil firing, 50% load, 30°F; tons/year based on 8,510 hrs/yr gas firing and 250 hrs/yr oil firing; 59°F conditions.**	

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: **10% opacity**	4. Equivalent Allowable Emissions: **139.6** lb/hour **11.6** tons/year
5. Method of Compliance (limit to 60 characters): **Annual VE test; EPA Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Oil firing - 30°F; 50% load; annual based on 59°F; 100% load, 250 hrs/yr.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM_{10}**	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference:	7. Emissions Method Code:
8. Calculation of Emissions (limit to 600 characters):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

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: **10% opacity**	4. Equivalent Allowable Emissions: **9.1** lb/hour **38.5** tons/year
5. Method of Compliance (limit to 60 characters): **VE Test, EPA Method 9**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Gas firing - 30°F, 100% load; annual based on 59°F; 100% load, 8,760 hrs/yr.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 2

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: **10** % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance: **Annual VE Test EPA Method 9**	
5. Visible Emissions Comment (limit to 200 characters):	

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

Continuous Monitoring System: Continuous Monitor 1 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_X**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **various** Model Number:	Serial Number: **various**
5. Installation Date: **01 Jan 1999**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **NO_X CEM proposed to meet requirements of 40 CFR Part 75, Monitoring Plan submitted to FDEP.**	

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: **100** % Maximum Period of Excess Opacity Allowed: **6** min/hour	
4. Method of Compliance: **None**	
5. Visible Emissions Comment (limit to 200 characters): **FDEP Rule 62-210.700(1). Allowed for 2 hours (120 minutes) per 24 hours for start up, shutdown and malfunction.**	

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

Continuous Monitoring System: Continuous Monitor 2 of 2

1. Parameter Code: **EM**	2. Pollutant(s): **NO_X**
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Westinghouse** Model Number:	Serial Number:
5. Installation Date: **01 Jan 1999**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Parameter Code: WTF. Required by 40 CFR part 60; subpart GG; 60.334.**	

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

Supplemental Requirements

1. Process Flow Diagram	[ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification	[ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment	[ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities	[ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report	[ ] Attached, Document ID:________ [X] Previously submitted, Date: April 14, 2000 [ ] Not Applicable
6. Procedures for Startup and Shutdown	[ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
7. Operation and Maintenance Plan	[ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application	[ ] Attached, Document ID:________ [X] Not Applicable
9. Other Information Required by Rule or Statute	[ ] Attached, Document ID:________ [X] Not Applicable
10. Supplemental Requirements Comment:	

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
[X] Attached, Document ID:________ [ ] 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: LMC-EU1-J13 [ ] Not Applicable

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

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

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

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

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

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

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

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

[X] Not Applicable

ATTACHMENT LMC-EU1-J13

IDENTIFICATION OF ADDITIONAL APPLICABLE REQUIREMENTS

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of application for Permit Modification by:

Mr. Ronald W. Tomlin, Assistant Managing Director
City of Lakeland Electric & Water Utilities
501 East Lemon Street
Lakeland, Florida 33801-5079

DEP File No. 1050004-004AC
Permit No. PSD-FL-245
C.D. McIntosh, Jr. Power Plant, Unit No. 5
Polk County

_______________________________________/

Enclosed is the Final Permit Number PSD-FL-245 to construct a 250 megawatt simple cycle combustion turbine with a once-through heat generator and a 1.05 million gallon fuel oil storage tank at the C.D. McIntosh, Jr. Power Plant, located at 3030 East Lake Parker Drive, Lakeland, Polk County. This permit is issued pursuant to Chapter 403, Florida Statutes.

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.

A A Linero, P.E.

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 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 7/10/98 to the person(s) listed:

Mr. Ronald W. Tomlin, City of Lakeland *
Ms. Farzie Shelton, City of Lakeland
Mr. Brian Beals, EPA
Mr. John Bunyak, NPS
Mr. Bill Thomas, SWD
Mr. Buck Oven, DEP
Mr. Ken Kosky, P.E., Golder Associates
Mr. Joe King, Polk County

Clerk Stamp

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

Charlotte J. Hayes 7/10/98
(Clerk) (Date)

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

PERMITTEE:

City of Lakeland
Department of Electric & Water Utilities
501 East Lemon Street
Lakeland, Fl 33801-5079

File No.	1050004-004-AC
FID No.	1050004-004
SIC No.	4911
Permit No.	PSD-FL-245
Expires:	June 30, 2002

Authorized Representative:
Ronald W. Tomlin
Assistant Managing Director

PROJECT AND LOCATION:

Permit for the construction of 250 megawatt (MW) simple cycle, gas-fired, stationary combustion turbine (CT), a once-through steam generator, and a 1.05 million gallon storage tank for back-up distillate fuel oil. Conditions are included for possible future conversion to a 350 megawatt combined cycle installation including a heat recovery steam generator provided there are no increases in emissions associated with the conversion. The turbine is designated as Unit No. 5 and will be located at the C.D. McIntosh, Jr., Power Plant, 3030 East Lake Parker Drive, Lakeland, Polk County. UTM coordinates are: Zone 17; 409.0 km E; 3106.2 km N.

STATEMENT OF BASIS:

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

Attached appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

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

SECTION I. FACILITY INFORMATION

SUBSECTION A. FACILITY DESCRIPTION

The existing facility includes: two small diesel powered electric generators; one small gas and distillate-fired combustion turbine; one 90 MW gas and fuel oil-fired steam generator; one 115 MW gas and fuel oil-fired steam generator; and one 364 MW multiple (primarily coal) fuel-fired steam generator. This permit is for the installation of: a 250 MW simple cycle, gas-fired, stationary combustion turbine; a once-through steam generator; a 1.05 million gallon storage tank for back-up (0.05 percent sulfur) distillate fuel oil; and an 85-foot stack. It is possible that in the future the turbine will be converted by the addition of a heat recovery steam generator and a new stack to a 350 MW combined cycle operation without increases in emissions.

Emissions from the McIntosh Unit 5 will be initially controlled by Dry Low NO_X combustors, wet injection when firing fuel oil, use of inherently clean fuels, and good combustion practices. Ultimately the combustors will be replaced and nitrogen oxides emissions reduced by more sophisticated Ultra Low NO_X burners. Otherwise emissions will be reduced by the addition of a selective catalytic reduction (SCR) system.

SUBSECTION B. EMISSION UNITS

This permit addresses the following emission units:

ARMS EMISSION UNIT NO.	SYSTEM	EMISSION UNIT DESCRIPTION
028	Power Generation	250 Megawatt Combustion Turbine and Once Through Steam Generator
029	Fuel Storage	1.05 Million Gallon Fuel Oil Storage Tank

SUBSECTION C. REGULATORY CLASSIFICATION

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

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Per Table 62-212.400-2, modifications (such as the construction of Unit 5) at the facility resulting in emissions increases greater than 40 TPY of NO_X or SO_2, 25/15 TPY of PM/PM_{10}, or 3 TPY of fluorides (F) require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

This facility is also subject to the provisions of Title IV, Acid Rain, Clean Air Act as amended in 1990.

SECTION I. FACILITY INFORMATION

SUBSECTION D. PERMIT SCHEDULE

- 04/22/98 Notice of Intent published in The Ledger
- 04/23/98 Distributed Intent to Issue Permit
- 04/01/98 Application deemed complete
- 12/08/97 Received Application

SUBSECTION E. RELEVANT DOCUMENTS:

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

- Application received on December 8, 1997
- Department letters dated January 5, January 12, March 9, 1998, and April 27, 1998
- Comments and letters from the National Park Service dated January 6, January 12, April 2 and April 15, 1998.
- EPA letters dated February 10 and March 6, 1998.
- City of Lakeland letters dated March 4, March 11, March 31, and May 6, 1998.
- Letters from Westinghouse dated March 25, March 30, and March 31, 1998.
- Department's Intent to Issue and Public Notice Package dated April 22, 1998.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this permit.

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-1344. All documents related to reports, tests, and notifications should be submitted to the DEP Southwest District office (DEPSW), 3804 Coconut Palm Drive, Tampa, Florida 33619 and phone number 813/744-6100.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212]
6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)].
7. BACT Determination: In accordance with paragraph (4) of 40 CFR 52.21(j) the Best Available Control Technology (BACT) determination shall be reviewed and modified as appropriate in the event of a conversion to combined cycle operation. This paragraph states: "For phased construction project, the determination of best available control technology shall be reviewed and modified as appropriate at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of the project. At such time, the owner or operator of the applicable stationary source may be required to demonstrate the adequacy of any previous determination of best available control technology for the source."

SECTION II. EMISSION UNIT(S) GENERAL REQUIREMENTS

This reassessment will be conducted for this project only if the conversion to combined cycle operation is accompanied by any increases in heat input limits, hours of operation, oil firing, low or baseload operation, short-term or annual emission limits, annual fuel heat input limits or similar changes. At a minimum, conversion to combined cycle operation will require a modification of this permit to reflect the ultimate facility description, the higher power production rates and review of the actual control equipment design. [40 CFR 52.21(j)(4), Rule 62-4.070 F.A.C.]

8. Application for Title V Permit: An application for a Title V operating permit, pursuant to Chapter 62-213, F.A.C., must be submitted to the DEP's Bureau of Air Regulation, and a copy to the Department Southwest District office (DEPSW). [Chapter 62-213, F.A.C.]

9. New or Additional Conditions: Pursuant to Rule 62-4.080, F.A.C., for good cause shown and after notice and an administrative hearing, if requested, the Department may require the permittee to conform to new or additional conditions. The Department shall allow the permittee a reasonable time to conform to the new or additional conditions, and on application of the permittee, the Department may grant additional time. [Rule 62-4.080, F.A.C.]

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

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

12. Permit Extension: The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.080, F.A.C.).

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

APPLICABLE STANDARDS AND REGULATIONS:

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

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

3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements

4. ARMS Emission Unit 028, Power Generation, consisting of a 250 megawatt combustion turbine with a once-through steam generator shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).

5. ARMS Emission Unit 029, Fuel Storage, consisting of a 1.05 million gallon distillate fuel oil storage tank shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C.

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

GENERAL OPERATION REQUIREMENTS

7. Fuels: Only pipeline natural gas or maximum 0.05 percent sulfur fuel oil No. 2 or superior grade of distillate fuel oil shall be fired in this unit. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

8. Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to Unit 5 at ambient conditions of 59°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 2,174 million Btu per hour (mmBtu/hr) when firing natural gas, nor 2,236 mmBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

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

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

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

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

13. Maximum allowable hours of operation for the stationary gas turbine and once-through steam generator are 8760. Fuel usage as heat input, while burning natural gas in the stationary gas turbine, shall not exceed 15.639×10^{12} BTU (LHV) per year (rolled monthly) until the unit achieves the NO_X emission limits (other than the initial ones) given in Specific Condition 21. Thereafter, only the hourly heat input limits given in Specific Condition 8 apply. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

14. Fuel usage as heat input, while burning fuel oil in the stationary gas turbine, shall not exceed 559×10^9 BTU (LHV) per year (rolled monthly). [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

Control Technology

15. Westinghouse Dry Low NO_X (DLN) combustors shall be installed on the stationary combustion turbine to control nitrogen oxides (NO_X) emissions while firing natural gas. [Design, Rule 62-4.070, F.A.C.]

16. The Dry Low NO_X (DLN) combustors shall be replaced with Westinghouse Ultra Low NO_X (ULN) combustors to accomplish further NO_X control in order to achieve the emission limits specified in Specific Condition 20 and 21. A high temperature selective catalytic reduction (Hot SCR) system or a low temperature SCR system shall be installed and in operation (together with DLN or ULN combustors) not later than May 1, 2002 if the emission limits specified in Specific Condition No 20 and 21 are not achievable by ULN combustors by this date. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

17. The permittee shall design the stationary gas turbine, ducting, possible future heat recovery steam generator, and stack(s) to accommodate installation of SCR equipment and/or oxidation catalyst in the event that the ULN technology fails to achieve the NO_X limits given in Specific Condition No. 20 and 21 or the carbon monoxide (CO) limits given in Specific Condition 22 are not met. [Rule 62-4.070, F.A.C.]

18. A water injection system shall be installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

19. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and ULN systems prior to their installation. DLN and ULN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize NO_X emissions and CO emissions. Operation of the DLN or ULN systems in the diffusion firing mode shall be minimized when firing natural gas. [Rule 62-4.070, and 62-210.650 F.A.C.]

EMISSION LIMITS AND STANDARDS

20. The following table is a summary of the BACT determination and is followed by the applicable specific conditions. Values for NO_X are corrected to 15% O_2. Values for CO are corrected to 15% O_2 only until May 1, 2002. [Rule 62-212.400, F.A.C.]

Operational Mode	NO_X (ppm)	CO (ppm)	VOC (ppm)	PM/Visibility (% Opacity)	Technology and Comments
Simple Cycle	25 - NG (basis) 237 lb/hr (24-hr avg) 42 - FO (3 hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	DLN on gas, WI on oil. Applies until 05/1/2002 . Clean fuels, good combustion
Simple Cycle	9 - NG (basis) 85 lb/hr (24-hr avg) 42 - FO (3 hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	ULN on gas, WI on oil. Applies after 05/1/2002 Clean fuels, good combustion
Simple Cycle	9 - NG (3 hr avg) 15 - FO (3-hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Hot SCR. Applies not later than 05/1/2002 if 9 ppm NO_X not achievable by ULN. Clean fuels, good combustion.
Combined Cycle	7.5 - NG (3 hr avg) 15 - FO (3-hr avg)	25 - NG or 10 - Ox Cat 90 - FO	4 - NG 10 - FO	10	Conventional SCR unless simple cycle limits are achieved on or before 05/01/2002. Clean fuels, good combustion

21. Nitrogen Oxides (NO_X) Emissions:

- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.
- Until May 1, 2002, the concentration of NO_X in the exhaust gas shall not exceed 237 lb/hr (at ISO conditions) on a 24 hr block average (basis 25 ppm @ 15% O_2, full load) when firing natural gas and 42 ppmvd at 15% O_2 when firing fuel oil on the basis of a 3 hr average as measured by the continuous emission monitoring system (CEMS). In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall exceed neither 25 ppm @15% O_2 nor 237 lb/hr (when firing natural gas) and shall exceed neither 42 ppm @15% O_2 nor 413 lb/hr (when firing fuel oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- Not later than May 1, 2002, the concentration of NO_X concentrations in the exhaust gas shall not exceed 85 lb/hr (at ISO conditions) on a 24 hr block average (basis 9 ppm @ 15% O_2) when firing natural gas and 42 ppmvd at 15% O_2 when firing fuel oil on the basis of a 3 hr average as measured by the CEMS. In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall exceed neither 9 ppm @15% O_2 nor 85 lb/hr (when firing natural gas) and shall exceed neither 42 ppm @15% O_2 nor 413 lb/hr (when firing fuel oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- If Hot SCR is installed, achievable short-term NO_X concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 9 ppmvd at 15% O_2 when firing natural gas. NO_X emissions shall not exceed 9 ppmvd at 15% O_2 when firing natural gas and 15 ppmvd at 15% O_2 when firing fuel oil on the basis of a 3-hr average, as measured by the CEMS. In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 85 lb/hr (when firing natural gas) and 148 lb/hr (when firing fuel oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]
- If conventional SCR is installed in conjunction with conversion to combined cycle operation, achievable short-term NO_X concentrations in the exhaust gas shall be demonstrated at baseload during the first compliance test following installation not to exceed 7.5 ppmvd at 15% O_2 when firing natural gas. If conventional SCR catalyst is installed, NO_X emissions shall not exceed 7.5 ppmvd at 15% O_2 when firing natural gas and 15 ppmvd at 15% O_2 when firing fuel oil on the basis of 3-hr average, as measured by the CEMS. In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 71.1 lb/hr (when firing natural gas) and 148 lb/hr (when firing fuel oil) to be demonstrated by stack test. [Rule 62-212.400, F.A.C.]

SECTION III. EMISSION UNIT(S) SPECIFIC CONDITIONS

22. Carbon Monoxide (CO) emissions: Prior to May 1, 2002, the concentration of CO (@15% O_2 in the exhaust gas when firing natural gas shall not exceed 25 ppmvd when firing natural gas and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 145 lb/hr (when firing natural gas) and 539 lb/hr (when firing fuel oil). [Rule 62-212.400, F.A.C.]

    After May 1, 2002, the concentration of CO in the exhaust gas when firing natural gas shall not exceed 25 ppmvd when firing natural gas and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 106 lb/hr (when firing natural gas) and 386 lb/hr (when firing fuel oil). [Rule 62-212.400, F.A.C.]

23. Sulfur Dioxide (SO_2) emissions: SO_2 emissions (at ISO conditions) shall not exceed 7.2 pounds per hour when firing pipeline natural gas and 127 pounds per hour when firing maximum 0.05 percent sulfur No. 2 or superior grade distillate fuel oil as measured by applicable compliance methods described below. Emissions of SO_2 shall not exceed 38.4 tons per year. [Rules 62-4.070 and 62-212.400, F.A.C. to avoid PSD Review]

24. Visible emissions (VE): VE emissions shall not exceed 10 percent opacity when firing natural gas or No. 2 or superior grade of fuel oil.

25. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 4 ppmvd when firing natural gas and 10 ppmvd when firing fuel oil as assured by EPA Methods 18, and/or 25 A. VOC emissions (at ISO conditions) shall not exceed 10 lb/hr (when firing natural gas) and 25 lb/hr (when firing fuel oil). [Rule 62-212.400, F.A.C.]

EXCESS EMISSIONS

26. Excess emissions resulting from startup, shutdown, malfunction or fuel switching shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed four hours in any 24-hour period for cold startup or two hours in any 24-hour period for other reasons unless specifically authorized by DEP for longer duration.

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

28. Excess Emissions Report: If excess emissions occur due to malfunction, the owner or operator shall notify DEP's Southwest District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. [Rules 62-4.130 and 62-210.700(6), F.A.C.]

COMPLIANCE DETERMINATION

29. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, for each fuel, at which this unit will be operated, but not later than 180 days of initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1997 version), and adopted by reference in Chapter 62-204.800, F.A.C. Emission limits compliance dates shall conform to the timetable specified on Specific Condition No. 20.

30. Initial (I) performance tests shall be performed on Unit 5 while firing natural gas as well as while firing fuel oil. Initial tests shall also be conducted after any modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment, including installation of Ultra Low NO_X burners, Hot SCR, or conventional SCR. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on Unit 5 as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG and (I, A) short-term NO_X BACT limits (Method 7E or RATA test data may be used to demonstrate compliance for annual test requirement)
- EPA Reference Method 18, and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

31. <u>Continuous compliance with the NO_X emission limits</u>: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 24-hr block average (DLN or ULN technology) or a 3-hr average (if SCR is used). Based on CEMS data, a separate compliance determination is conducted at the end of each operating day (or 3-hr period when applicable) and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous operating day (or 3-hr period when applicable). Valid hourly emission rates shall not included periods of startup (including fuel switching), shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in Condition 28.

A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]

32. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas and maximum 0.05 percent sulfur (by weight) No. 2 or superior grade distillate fuel oil, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard and the 0.05% S limit, fuel oil analysis using ASTM D2880-71 or D4294 (or equivalent) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule. The applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. 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 pursuant to 40 CFR 60.335(e) (1997 version).

33. Compliance with CO emission limit: An initial test for CO, shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted concurrent with the annual RATA testing for NO_X required pursuant to 40 CFR 75 (required for gas only).

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

35. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Test procedures shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapter 62-204.800 F.A.C.

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

37. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible

emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

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

NOTIFICATION, REPORTING, AND RECORDKEEPING

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

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

MONITORING REQUIREMENTS

41. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from Unit 5. Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards, listed in Specific Condition No 20 and 21, shall be reported to the DEP Southwest District Office pursuant to Rule 62-4.160(8), F.A.C. Following the format of 40 CFR 60.7, periods of startup, shutdown, malfunction, and fuel switching shall be monitored, recorded, and reported as excess emissions when emission levels exceed the BACT standards listed in Specific Condition No. 20 and 21. [Rule 62-204.800 and 40 CFR 60.7 (1997 version)]

42. CEMS in lieu of Water to Fuel Ratio: Subject to EPA approval, the NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1997 version). Subject to EPA approval, the calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1997 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emission rates for NO_X on Unit 5 shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.

43. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75.

Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. Data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the Department's Southwest District Office (DEPSWD) for review at least 90 days prior to installation.

44. Fuel Oil Monitoring Schedule: The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 or superior grade fuel oil received at the C.D. McIntosh , Jr. Power Plant, an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).

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

- Monitoring of natural gas nitrogen content shall not be required.
- Analysis of the sulfur content of natural gas shall be conducted using one of the EPA-approved ASTM reference methods in Specific Condition No. 32 for the measurement of sulfur in gaseous fuels, or an approved alternative method. Once Unit 5 becomes operational, monitoring of the sulfur content of the natural gas shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then fuel sulfur monitoring shall be conducted once per quarter for six quarters and after that, semiannually.
- Should any sulfur analysis indicate noncompliance with 40 CFR 60.333, the City shall notify DEP of such excess emissions and the customized fuel monitoring schedule shall be reexamined. The sulfur content of the natural gas will be monitored weekly during the interim period while the monitoring schedule is reexamined.
- The City shall notify DEP of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content variation of greater than 1 grain per 100 cubic foot of natural gas) shall be considered as a change in the natural gas supply. Sulfur content of the natural gas will be monitored weekly by the natural gas supplier during the interim period when this monitoring schedule is being reexamined.
- Records of sampling analysis and natural gas supply pertinent to this monitoring schedule shall be retained by the City for a period of five years, and shall be made available for inspection by the appropriate regulatory personnel.
- The City may obtain the sulfur content of the natural gas from the fuel supplier (Florida Gas Transmission) provided the test methods listed in Specific Condition E.4 are used.

46. Determination of Process Variables:

- The permittee shall operate and maintain equipment and/or instruments necessary to determine process variables, such as process weight input or heat input, when such data is needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
- Equipment and/or instruments used to directly or indirectly determine such process variables, including devices such as belt scales, weigh hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value [Rule 62-297.310(5), F.A.C]

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

C. D. McIntosh, Jr. Power Plant
City of Lakeland Electric & Water Utilities
PSD-FL-245 and 1050004-004AC
Lakeland, Polk County, Florida

BACKGROUND

The applicant, The City of Lakeland (City), proposes to install a nominal 250 megawatt (MW) (net) new simple cycle combustion turbine at the existing C.D. McIntosh, Jr. Power Plant located at 3030 East Lake Parker Drive in Lakeland, Polk County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_X). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The unit to be installed is a 230 MW Westinghouse 501 G combustion turbine and includes a once through steam generator (OTSG) which provides steam for steam cooling of critical components and injection for further cooling and power augmentation to 250 MW. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated April 22, 1998, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on December 8, 1997 and included a proposed BACT proposal prepared by the applicant's consultant, Golder Associates Inc.

REVIEW GROUP MEMBERS:

A. A. Linero, P.E., and Teresa Heron, Review Engineer

BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Particulate Matter	Pipeline Natural Gas No. 2 Distillate Oil Use (250 hr/yr) Combustion Controls	9.1 lb/hr (Gas) 140 lb/hr, 0.05% sulfur (Oil)
Volatile Organic Compounds	As Above	4 ppm (Gas) 10 ppm (Oil)
Visibility	As Above	20 percent
Carbon Monoxide	As Above	50 ppm (Gas, baseload) 90 ppm (Oil, baseload)
Nitrogen Oxides	Dry Low NO_X Burners (Gas) Water Injection (Oil)	25 ppm @ 15% O_2 (Gas, baseload) 42 ppm @ 15% O_2 (Oil, baseload)

The unit, as described above, would emit approximately 852-863 tons per year (TPY) of NO_X, 761-1,264 TPY of CO, 37-94 TPY of VOC, 39 TPY of SO_2, and 41 TPY of PM/PM_{10}. The basis is 7,008 hours of operation including 250 hours of oil firing and 1050 hours at 50% load.

Project Location	Power Output and Duty	NO_X Limit ppm @ 15% O_2 and Fuel	Technology	Comments
Cataula, GA	1200 MW SC PKR	25 - NG 42 - No. 2 FO	DLN WI	4x300 MW **WH 501G** CTs CTs rated 230 MW @ ISO, NG
Mid-GA Cogen, GA	308 MW CC **CON**	9 - NG 20 - No. 2 FO	DLN & SCR	2x119 MW **WH 501D5A** CTs
CCC, VA	398 MW **SC PKR**	42/65 - No. 2 FO	WI	3x132.5 MW CTs 2000 (500 @ Peak) hr/yr/CT
PREPA, PR	248 MW **SC CON**	10 - No. 2 FO	WI & Hot SCR	3x83 MW CTs
Tiger Bay, **FL**	270 MW CC **CON**	15/10 - NG 42 - No. 2 FO	DLN &/or SCR WI	184 MW GE MS7001FA CT DLN/15 ppm or SCR/10 ppm
Hines Polk, **FL**	485 MW CC **CON**	12 - NG 42 - No. 2 FO	DLN WI	2x165 MW **WH 501**FC CTs Canceled GE CTs
Tallahassee, **FL**	260 MW CC **CON**	12 - NG 42 - No. 2 FO	DLN WI	160 MW GE MS 7231FA CT DLN Guarantee is 9 ppm
Eco-Electrica, PR	461 MW CC **CON**	7 - NG 9 - LPG, No. 2 FO	DLN & SCR	2x160 MW **WH 501**F CTs
Sithe/IPP, NY	1012 MW CC **CON**	4.5 - NG	DLN & SCR	4 x160 MW GE 7FA CTs
Hermiston, OR	474 MW CC **CON**	4.5 - NG	SCR	2x160 MW GE 7FA CTs
Berkshire, MA	272 MW CC **CON**	3.5 - NG (LAER) 9.0 - No. 2 FO	DLN & SCR WI & SCR	178 MW ABB GT24 CT

SC = Simple Cycle   CON = Continuous   DLN = Dry Low NO_X Combustion   GE = General Electric
CC = Combined Cycle   PKR = Peaking Unit   SCR = Selective Catalytic Reduction   WH = Westinghouse
NG = Natural Gas   FO = Fuel Oil   LPG = Liquefied Propane Gas   ABB = Asea Brown Bovari
CT = Combustion Turbine   ISO = 59°F   WI = Water or Steam Injection   ppm = parts per million
Factors in Common with City of Lakeland Project are bolded. All determinations are BACT unless denoted as LAER.

Project Location	CO - ppm (or lb/mmBtu)	VOC - ppm (or lb/mmBtu)	PM - lb/mmBtu (or gr/dscf or lb/hr)	Technology and Comments
Cataula, GA	25 - NG @15% O_2 75 - FO@ 15% O_2	0.01 lb/mmBtu	0.005 - NG 0.03 - FO	Clean Fuels Good Combustion
Mid-GA Cogen, GA	10 - NG 30 - FO	6 - NG 30 - FO	18 lb/hr - NG 55 lb/hr - FO	Clean Fuels Good Combustion
CCC, VA	Not PSD	Not PSD	0.0216 - FO	Clean Fuels Good Combustion
PREPA, PR	9 - FO @15% O_2	11 - FO @15% O_2	0.0171 gr/dscf	Clean Fuels Good Combustion
Tiger Bay, FL	0.045 lb/mmBtu-NG 0.053 lb/mmBtu-FO		0.053 - NG 0.009 - FO	Clean Fuels Good Combustion
Hines Polk, FL	25 - NG 30 - FO	7 - NG 7 - FO	0.006 - NG 0.01 - FO	Clean Fuels Good Combustion
Tallahassee, FL	25 - NG 90 - FO			Clean Fuels Good Combustion
Eco-Electrica, PR	33 - NG/LPG @15% O_2 33 - FO @15% O_2	1.5/2.5 - NG/LPG 6 - FO	0.0053 - NG/LPG 0.0390 - FO	Clean Fuels Good Combustion
Sithe/IPP, NY	13 - NG			Clean Fuels Good Combustion
Hermiston, OR	15 - NG			Clean Fuels Good Combustion
Berkshire, MA	4 - NG (LAER) 5 - FO (LAER)	4 - NG 16 - FO	0.0105 - NG 0.0468 - FO	Clean Fuels CO Catalyst

NO_X Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are about 25 ppm when firing gas and 42 ppm when firing fuel oil in large combustion turbines. These values often form the basis for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection increase emissions of both of these pollutants.

Combustion Controls

The excess air in lean combustion, cools the flame and reduces the rate of thermal NO_X formation. Lean premixing of fuel and air prior to combustion can further reduce NO_X emissions. This is accomplished by minimizing localized fuel-rich pockets (and high temperatures) that can occur when trying to achieve lean mixing within the combustion zones.

The above principle is depicted in Figure 1 for a can-annular combustor operating on gas. For ignition, warm-up, and acceleration to approximately 20 percent load, the first stage serves as the complete combustor. Flame is present only in the first stage, which is operated as lean stable combustion will permit. With increasing load, fuel is introduced into the secondary stage, and combustion takes place in both stages. When the load reaches approximately 40 percent, fuel is cut off to the first stage and the flame in this stage is extinguished. The venturi ensures the flame in the second stage cannot propagate upstream to the first stage. When the fuel in the first-stage flame is extinguished (as verified by internal flame detectors), fuel is again introduced into the first stage, which becomes a premixing zone to deliver a lean, unburned, uniform mixture to the second stage. The second stage acts as the complete combustor in this configuration.

Combustors used in Westinghouse products are shown in Figure 2. These operate according to the same principles as described above. However they have different characteristics and do not reach the so-called fully pre-mixed operation until the load is over 50 percent.

The emission characteristics of General Electric's Dry Low NO_X (DLN 2) combustors are given in Figure 3. NO_X concentrations are higher in the exhaust at lower loads because at lower loads, the combustor do not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 25 parts per million (ppm) at loads between 40 and 100 percent of capacity, but concentrations as high as 100 ppm at less than 50 percent of capacity. GE has since upgraded its combustors and this description is not precise for its more advanced DLN 2.6

In all but the most recent gas turbine combustor designs, the high temperature combustion gases are cooled to an acceptable temperature with dilution air prior to entering the turbine (expansion) section. The sooner this cooling occurs, the lower the thermal NO_X formation. Cooling is also required to protect the first stage nozzle. When this is accomplished by air cooling, the air is injected into the component and is ejected into the combustion gas stream, causing a further drop in combustion gas temperature. This, in turn, results in a lower achievable thermal efficiency for the unit.

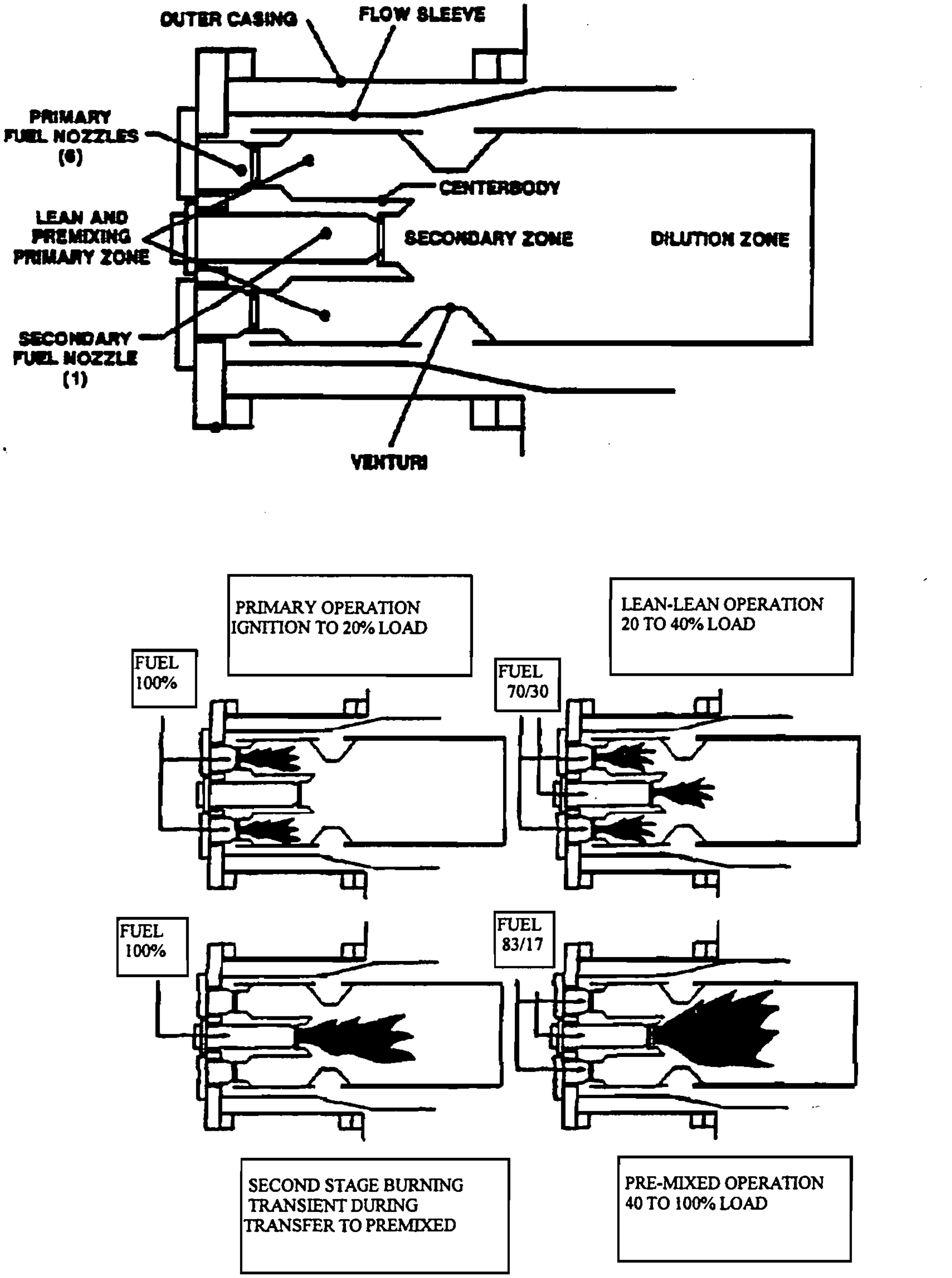

Figure 1 - Cross Sections of a Lean Premixed Can-annular Combustor

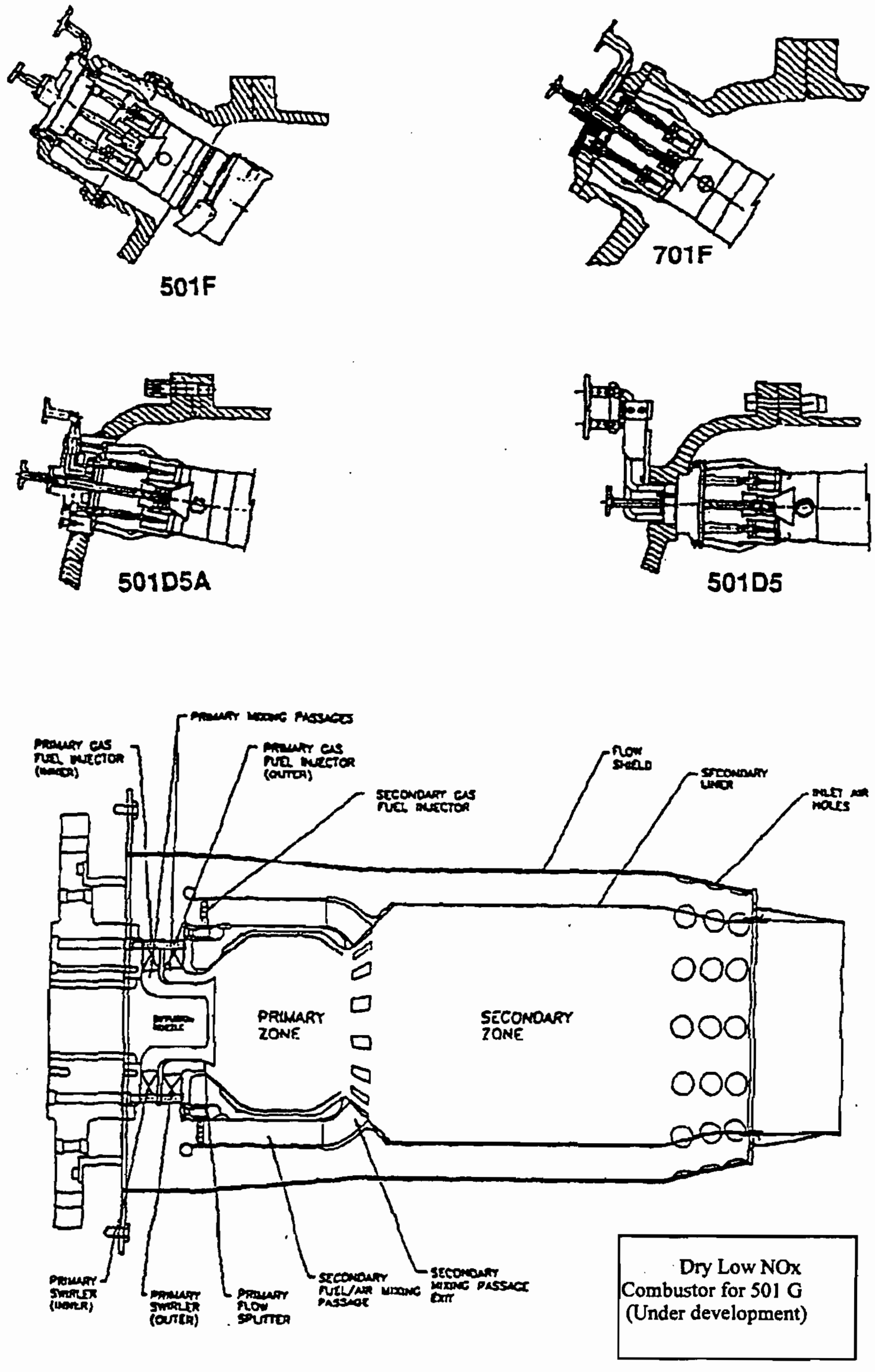

Figure 2 - Westinghouse Dry Low NOx Combustors

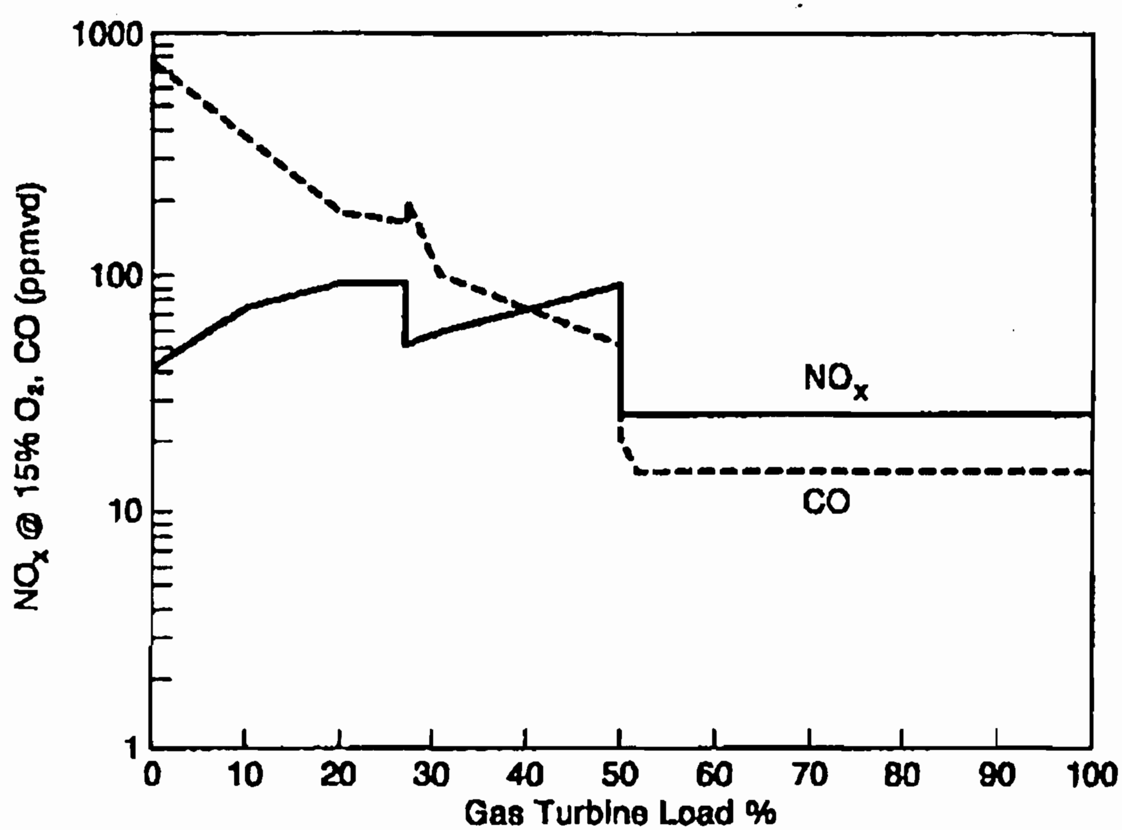

Figure 3   Emissions performance for DLN-2 combustors firing natural gas

Source: General Electric GER-3568E, 1996

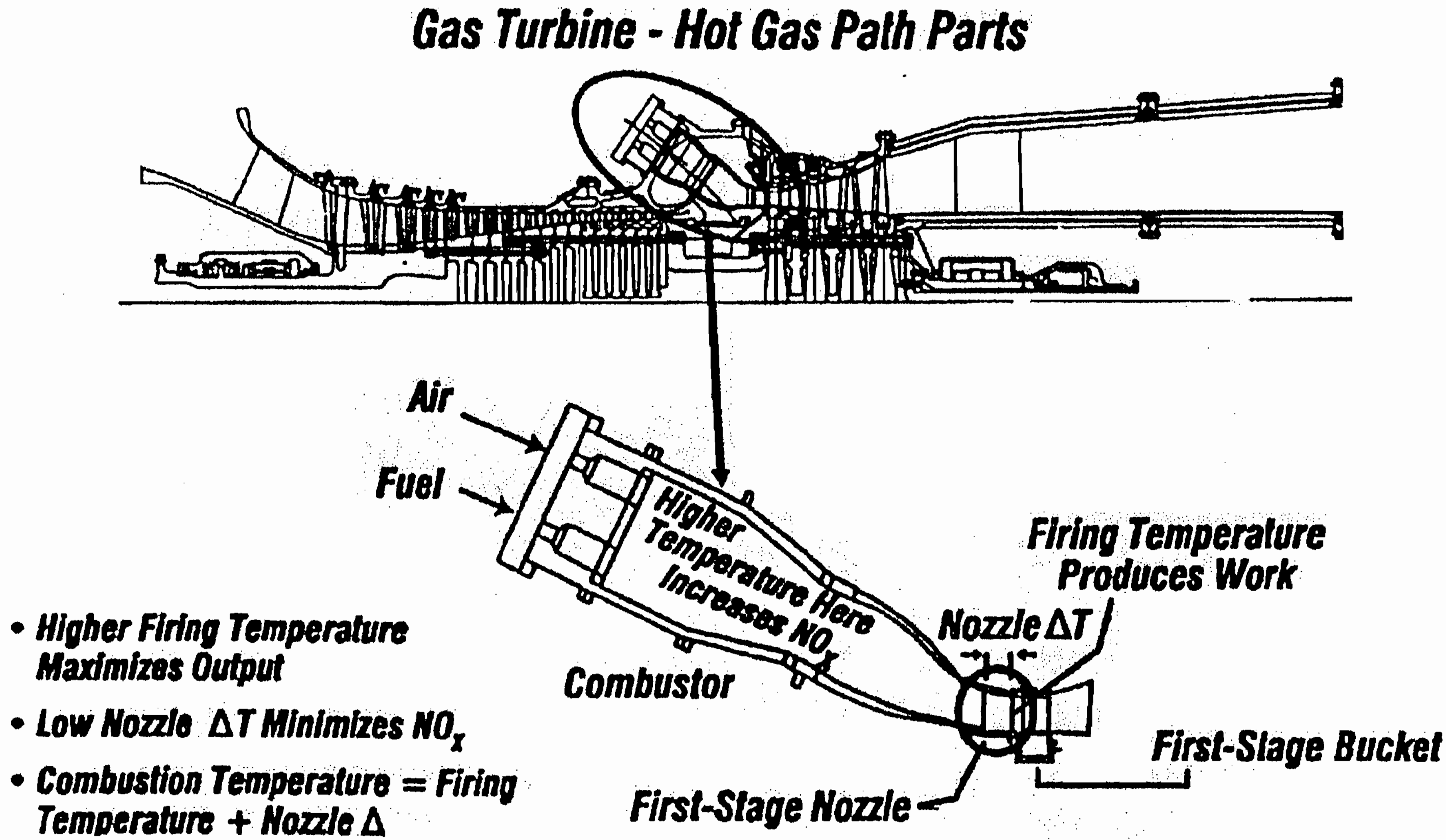

Figure 4. Relationship — combustion temperature to firing temperature

REVIEW OF PARTICULATE MATTER (PM/PM_{10}) CONTROL TECHNOLOGIES:

Particulate matter is generated by various physical and chemical processes during combustion and will be affected by the design and operation of the NO_X controls. The particulate matter emitted from this unit will mainly be less than 10 microns in diameter (PM_{10}).

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and will be used for approximately 250 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air. The City indicated that the PM_{10} emissions will not exceed 0.01 gr/scf when firing natural gas and pointed out that such a value is equal to a typical specification for baghouse design. Annual emissions of PM_{10} are expected to be approximately 30 tons for natural gas and less than 15 tons for fuel oil.

REVIEW OF CARBON MONOXIDE(CO) CONTROL TECHNOLOGIES

CO is emitted from combustion turbines due to incomplete fuel combustion. Combustion design and catalytic oxidation are the control alternatives that are viable for the project. The most stringent control technology for CO emissions is the use of an oxidation catalyst.

Most installation using catalytic oxidation are located in the Northeast. Besides the Berkshire installation listed above, CO oxidation catalyst has been installed at the 240 MW Brooklyn Navalyard Facility, the 240 MW Masspower facility, the 165 MW Pittsfield Generating Plant in Massachusetts, and the 345 MW Selkirk Generating Plant in New York. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load.

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. By comparison, the values of 50 and 90 ppm for gas and oil respectively at baseload proposed in the City's application appear high.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. There are no viable add-on control techniques as the combustion turbine itself is very efficient at destroying VOC. The limits proposed for this project are 4 and 10 ppm for gas and oil firing respectively.

BACKGROUND ON SELECTED GAS TURBINE

The City has already committed to the purchase of a 230 MW Westinghouse 501 G simple cycle gas turbine.[1] The unit was already under construction by Westinghouse and awaiting sale. The contract for the unit includes NO_X emission guarantees of 25 ppm on gas and 42 ppm on fuel oil.

The choice satisfies the City's immediate power needs and reserve capacity. If it is ultimately converted to combined cycle operation, the power generating capacity will be about 350 MW.[2] A contract was recently awarded to Sargent and Lundy to prepare bid specifications to convert the unit to combined cycle operation at the earliest opportunity.[3]

The conceptual and basic designs for the 501 G were jointly developed by Westinghouse and Mitsubishi Heavy Industries (MHI). Detailed designs were developed separately by the two companies and the units are not identical.[4] The first 501 G started operation in April of 1997 in Japan at the MHI Takasago Machinery Works 330 MW Demonstrator Combined Cycle Plant. The unit has the "highest firing temperature (1500 °C, 2732 °F) ever recorded, and a combined cycle efficiency of over 58 percent."[5] The efficiency is also the highest ever demonstrated for combined cycle turbine. NO_X emissions are controlled by multi-nozzle DLN combustor, followed by a selective catalytic reduction (SCR) system located within the heat recovery steam generator (HRSG).

The first commercial operation (i.e. not within MHI subsidiaries) of a "1500 °C" combined cycle unit will begin trial operation at the Tohoku Electric Higashui Niigata Power Plant in October, 1998.[6] The specific unit will be the "701 G," which is a larger, 50 Hertz version of the 501 G. Commercial operation will begin in July, 1999.

Westinghouse and General Electric continue to work on even larger and more efficient turbines. Westinghouse has already tested the compressor for its planned "H" Class turbine capable of achieving 60 percent efficiency while operating in combined cycle mode.[7] General Electric does not have an entry in the "G" class. However it is conducting trials in Greenville, South Carolina on the MS9001H, which is its 50 Hertz entry into the H Class. GE expects a combined cycle efficiency of 60 percent and generation of over 400 MW. GE plans to make its similar 60 Hertz MS7001H version available in 2001 or 2002.[8]

Westinghouse and General Electric are counting on further advancement and refinement of DLN technology to provide sufficient NO_X control for their turbines. In the case of the 501 G, steam cooling of the transition piece allows the unit the maintain the same NO_X formation potential as the 501 F while achieving a higher turbine inlet (firing) temperature. Examples of Westinghouse combustors are shown in Figure 2. These include their second generation of Dry Low NO_X combustors including their fully pre-mixed Piloted Ring Combustor.[9] Where required by BACT or LAER determinations of certain states, both companies incorporate SCR in combined cycle projects.[10,11]

The approach of progressively refining such technology is a proven one, even on some relatively large units. Basically this was the strategy adopted in Florida throughout the 1990's. Recently GE Frame 7 FA units (160 MW gas turbines with firing temperatures of 2400) met performance guarantees of 9 ppm with "DLN-2.6" burners at Fort St. Vrain, CO and Clark County, WA.[12]

Westinghouse will conduct two phases of testing in 1998 in its effort to develop Ultra Low NO_X (ULN) technology for its "F" Class to meet a NO_X level of 9-12 ppm by mid-2000.[13]

Both Westinghouse and General Electric are partners with the Department of Energy (DOE) in the Advanced Turbine Systems (ATS) Program.[14] The Mission/Vision Statement of ATS is to "develop base-load advanced turbine systems for commercial offering in the year 2000." Among the goals of the Program are 60 percent combined cycle efficiency while achieving NO_X emissions of 9 ppm or less.[15] The cost of producing the prototypes is estimated at $435,000,000 and $300,000,000 for the GE and Westinghouse projects respectively.[16] The goals of the ATS are reflected in the "H" Class units described above.

In simple cycle, continuous duty mode, the Westinghouse 501 G achieves an admirable efficiency of approximately 38 percent.[17] However this efficiency is much lower than what can be realized with the same unit (58 percent) when operating in combined cycle.[18] As discussed above, Sargent and Lundy have been contracted to prepare bid specifications to convert the unit to combined cycle.

The 25 ppm initial NO_X guarantee on natural gas appears high when compared with BACT determinations for continuous-duty or combined cycle units, such as those previously listed. It is also higher than the stated goal of the ATS Program. The simple cycle mode with the flexibility of switching (or not switching) to combined cycle operation, presents constraints in evaluating the feasibility and costs of various emission reduction options otherwise available. For this reason, the Department does not constrain itself to any presumed historical cost-effectiveness criteria or cost estimating procedures such as might apply to a project with a clearly defined staging schedule and final configuration. At the same time, however, the Department has a full appreciation of the goals of the ATS Program and does not want to arbitrarily impede progress toward its goals.

Westinghouse provided a technology update of the Westinghouse family of combustion turbines. It includes a schedule for the 501 G to reach low NO_X levels of 9-12 by Ultra Low NO_X. The structure of the schedule is similar to that described for their 501 F class unit. According to Westinghouse, the experience gained from the 501 F will be employed in development of Ultra LN for the 501 G. Basic design and laboratory testing of Piloted Ring Combustors (a candidate design for Ultra LN) for the 501 G is already underway. Initial field verification will be conducted beginning in mid-1999. Design modification and retesting will occur from mid-1999 through mid 2000. Additional design changes/tests will be carried out from mid-2000. Full commercial application will be implemented from 2001 through 2004.[8]

Westinghouse provided the City with a more specific schedule for the 501 G to be installed at Lakeland.[19] Westinghouse "fully anticipates having a combustion system available that meets the 9-12 NO_X requirement for the McIntosh No. 5 Unit within the next four years." That will occur in early 2002 and is within the general schedule given above. According to the same document, "since McIntosh Unit No. 5 is the demonstration project for the 501 G, there is a high probability that some field verification testing will be performed on the unit."

The proximity of Westinghouse technical staff in Orlando to the project site in Lakeland should enhance the probability of meeting Westinghouse's goal at an early date.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the Lakeland project assuming full load. Values for NO_X are corrected to 15% O_2. These limits or their equivalents in terms of pounds per hour, as well as the applicable averaging times, are given in the permit Specific Conditions. The rationale for the averaging times is discussed in the Final Determination addressing comments by the City and EPA and which is being issued concurrently with this determination.

Operational Mode	NO_X (ppm)	CO (ppm)	VOC (ppm)	PM/Visibility (% Opacity)	Technology and Comments
250 MW SC CON	25 - NG 42 - FO	25 - NG or 10 by Ox Cat 90 - FO	4 - NG 10 - FO	10	DLN on gas, WI on oil. Applies through April 30, 2002. Clean fuels, good combustion
250 MW SC CON	9 - NG 42 - FO	25 - NG or 10 by Ox Cat 90 - FO	4 - NG 10 - FO	10	ULN on gas, WI on oil. Applies after April 30, 2002. Clean fuels, good combustion
250 MW SC CON	9 - NG 15 - FO	25 - NG or 10 by Ox Cat 90 - FO	4 - NG 10 - FO	10	Hot SCR. Applies after April 30, 2002 if 9 ppm NO_X not achievable by ULN as described above. Clean fuels, good combustion.
350 MW CC CON	7.5 - NG 15 - FO	25 - NG or 10 by Ox Cat 90 - FO	4 - NG 10 - FO	10	Conventional SCR if converted to combined cycle, unless 9 ppm is attained by ULN or Hot SCR as described above. Clean fuels, good combustion

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The initial 25 and 42 ppm NO_X limits are guaranteed by Westinghouse.
- There is a clear plan for achieving emissions of 9-12 ppm at the Lakeland location within 4 years of April, 1998. This will occur in early 2002 - about 3 years after an early-1999 startup.
- The unit will be operated in simple cycle mode while maintaining the flexibility to expand at a future date to combined cycle operation through the addition of a 100 MW heat recovery steam generator. Therefore control options which are feasible for combined cycle units are not immediately applicable at commencement of operation. At project inception, this rules out Low Temperature (conventional) SCR which achieves a 4.5 ppm NO_X BACT limit at the Hermiston and Sithe/IPP projects above.
- The turbine has a very high exhaust temperature of about 1100 °F.[17] This is at the higher limit of the present operational temperature of Hot SCR zeolite catalyst.[20] Therefore the catalyst would have to placed *after* the OTSG. The PREPA simple cycle turbines have exhaust temperatures ranging from 824 to 1024 °F and the Hot SCR catalyst (which must achieve 10 ppm NO_X) is located *between* the turbine and the OTSG.[21]

- Hot SCR is technically feasible for gas.[22] The same evaluation states that the technology has not been demonstrated for oil. However the PREPA units have since been installed.[23] These operate solely on 0.15 percent sulfur fuel oil.[24] The Lakeland unit is proposed to operate only 250 hours per year on fuel oil of 0.05 percent sulfur.

- The levelized costs of NO_X removal by Hot SCR were estimated by the City as $5,236 per ton of NO_X removed. Other Hot and conventional SCR cost estimates submitted by the applicant are not considered in this evaluation because they are based on many conditional assumptions regarding possible ultimate project phasing scenarios which are not typically encountered when applying the methodology used by the applicant. Also the cost estimates do not consider a continuation of the actual downward trend in catalyst prices, progressively improving performance, and typically longer-than-expected life.

- The levelized costs derived in the application for Hot SCR at Lakeland are based on a quote from Engelhard. The vendor based the proposal on design operation on <u>fuel oil</u> with <u>guaranteed</u> NO_X reduction of 70 percent to 12.6 ppm @15% O_2.[25]

- In order to avoid allowing control on fuel oil to become the main design consideration, the Department obtained a budgetary estimate from Engelhard to guarantee reduction of NO_X emissions while operating on <u>gas</u> by 64 percent (from 25 to 9 ppm).[26] The replacement cost of the Hot SCR catalyst designed for gas is $1,600,000 versus the $2,800,000 estimated for the Lakeland project designed for oil. During the very few hours of operation on oil, <u>estimated</u> NO_X emissions from the 501 G controlled by Hot SCR will be approximately 13 ppm @15% O_2.

- The cost effectiveness for NO_X removal given for the PREPA simple cycle project is $2,200 per ton. The main reason for the relatively low levelized cost is that total costs are applied over a reduction of 40 ppm whereas the reduction in the Lakeland case is over a smaller reduction. The cost per ton of NO_X removed by Hot SCR at the PREPA project can be rescaled for the Lakeland project. This would involve a significant increase due lower removal. However there would be decreases due to the natural gas design, application on one large unit versus three smaller ones, and lower ammonia requirements. The resulting costs would be less than $4,000 per ton.

- Using much of the basic capital cost information developed by Lakeland, The National Park Service estimated the cost of NO_X removal by Hot SCR at $3,802 per ton (excluding the energy penalty) for the continuous duty 501 G. A further refinement of the Park Service estimate by including the energy penalty, using the revised catalyst cost data obtained by the Department, and assuming a five year <u>estimated</u> life for the catalyst (per Engelhard) would yield a cost-effectiveness closer to $3,500 per ton of NO_X removed.

- The Department concludes that Hot SCR is both technically and economically feasible now. The probability of success using this technology is at least as high as it is using the Ultra LN technology under development.

- According to Westinghouse, a heat exchange surface is required between the turbine and Hot SCR catalyst to insure an operational temperature less than 1100 °F is maintained. If a future HRSG is installed, Westinghouse indicates that the OTSG (which provides the steam for cooling and power augmentation) will be removed. This would expose the Hot SCR system (if installed) to unacceptable temperatures. Westinghouse does not believe relocation of catalyst to the HRSG is feasible and thus the Hot SCR system would be written off and possibly replaced by a conventional SCR system in the HRSG.

- The Department notes that the specifications under development by Sargent and Lundy for conversion to combined cycle operation are not yet available to the Department for evaluation. Therefore the Department does not concur that Hot SCR is not feasible based on conceivable future development scenarios.
- According to Westinghouse, the ultimate design of their ATS-based gas turbine has options for "recuperative cycles" working within combined cycles. These cycles can lower the gas temperature entering the steam cycle and appear to provide heat exchange surface to cool the gases and protect the Hot SCR system before the HRSG.
- There are various kinds of recuperative cycles - some of which make the combined cycle less efficient and others that which make it more efficient. According to a paper heralding the arrival of the 501 G, the author writes that "what is more significant is that the 501 G has been designed to incorporate the technology advances planned in the ATS program, such as intercooling and reheat, humidification and *chemical recuperation*, as and when they are good and ready."[2]
- The Department is not aware of actual plans to incorporate recuperation cycles in Westinghouse 501 products, the likely combined cycle efficiency benefits (or penalties), or their applicability to the Lakeland project by the time of conversion to combined cycle operation. The point is that ultimate wasting of Hot SCR equipment installed at startup, is not a foregone conclusion considering that many developments can occur within the time horizon of possible future project expansion scenarios.
- It is possible, and even likely, that Hot SCR catalysts will be improved (similar to refinement of Ultra LN) and can be used to replace the initial catalyst as it degrades. By the time the OTSG is removed for combined cycle conversion (e.g. 3-5 years), replacement catalyst might be able to withstand the higher temperature regime.
- Hot SCR has environmental and energy impacts including increased particulate emissions, undesirable (though unregulated) ammonia emissions, and energy penalties. All factors being equal, Ultra LN is a better control strategy than Hot SCR. A three year period to refine this technology to achieve similar emissions as Hot SCR is reasonable and not unprecedented.
- The Department does not conclude at this time that achieving 9-12 ppm of NO_X in three years by Ultra LN is an overall better strategy than immediately achieving 4.5 - 7.5 ppm by conventional SCR in a combined cycle unit. However, if the 9-12 ppm value can be achieved by ULN within the three years, subsequent installation of conventional SCR during a conversion to combined cycle may not be cost-effective.
- Three years after startup is equal to the longest period of time provided to any previous applicant to achieve Department BACT limits by DLN technologies. With the accumulated knowledge and experience from DLN technologies for smaller units, it should be possible to

achieve the Department's BACT limit for this project within three years after startup (if it achievable by Ultra LN technology on the 501G).

- The approach promotes further progress of the DOE ATS Program and falls within the realm of BACT determinations made by the Department in recent years.
- The Hot SCR scenario has, nevertheless, been included in the Department's determination for implementation in case that the Ultra LN strategy fails to reach the objectives within a reasonable period of time. If the City converts the unit to combined cycle mode in the near future, conventional SCR (with the catalyst in a low temperature regime within a HRSG) becomes immediately feasible, particularly if progress is slow on Ultra LN. Conventional SCR now rather than Ultra LN in three years, would be BACT at this time if the City planned to operate the unit in combined cycle mode at startup.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of clean, low ash, low sulfur fuels; and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure at the high temperature exiting the stack in simple cycle operation. Additionally, the higher emission mode will involve fuel oil firing which will occur only approximately 250 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT. Examples of installations with similar VE limits include the City of Tallahassee, Florida and the Berkshire, Massachusetts projects in the above table.
- CO emission estimates from the City's project are higher than for any pollutant. However the impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, or PM_{10}.
- The City evaluated the use of an oxidation catalyst designed for 90 percent reduction and having a two year catalyst life. The oxidation catalyst control system was estimated by the City to increase the total capital cost of the project by "about $2,000,000, with an annualized cost of $980,000 per year." The City estimated levelized costs for CO catalyst control at about $800 per ton to control CO emission to 10 ppm. This company operates three of the previously-mentioned facilities where CO catalyst is used. Catalytic CO control appears to be cost-effective for the Lakeland unit..
- In the 501 G Application Overview prepared by Westinghouse and included in the City's application for permit, the combustors have "initial emission levels less than the following:"[17]

Pollutant (ppm)	Natural Gas (no injection)	Distillate Oil (water injection)
Nitrogen Oxides	25	42
Carbon Monoxide	10	90
Unburned Hydrocarbons	5	20

- In an article included in the permit application, the author states "NO_X levels of less than 25 ppm on natural gas, less than 42 ppm on oil, while maintaining CO at less than 10 ppm will be specified for introductory machines."[2]
- Westinghouse tables of "expected performance" in the permit application for the specific unit, however, estimate CO emissions while burning natural gas as 50, 100, and 350 ppm when operating at baseload, 75% load, and 50% load respectively. While operating on oil the estimated values are 90, 125, and 350 ppm at baseload, 75%, and 50% respectively.
- The permit application states that the high emission limits are "a result of uncertainty associated with maintaining low NO_X emissions while keeping emissions of CO as low as possible over the load range of the machine." It also mentions that the Westinghouse Application Overview estimate is 10 ppm for CO and accordingly calculates a much higher alternative cost per ton of removal based on the lower expected starting point prior for catalytic oxidation.
- The Department will set CO limits achievable by good combustion equal to those set for the City of Tallahassee project of 25 ppm on gas and 90 ppm on oil. For reference, the FPC Hines Westinghouse 501 F project is limited to 25 ppm on natural gas and 30 ppm on oil. The Mid-Georgia Cogen Westinghouse 501 D5A project achieved its CO limits of 10 ppm on gas and 30 ppm on fuel oil.
- At the relatively high initial NO_X emission rate of 25 ppm, there should not be technical difficulties in achieving 25 ppm of CO with Dry Low NO_X technology. These values remain as appropriate objectives to meet with the Ultra Low NO_X technology under development. The oil case is relatively insignificant because of the limited firing time.
- It is up to the City to evaluate whether to meet the CO limits by combustion optimization or alternative lower limits achievable by catalytic oxidation. A plan describing how the limits will be met should be submitted prior to construction of the unit.
- VOC emission limits proposed by the City are at the lower end of values determined as BACT. Good Combustion is sufficient to achieve these low levels.

COMPLIANCE PROCEDURES

Pollutant	Compliance Procedure
Visible Emissions	Method 9
Volatile Organic Compounds	Method 18, 25, or 25A (initial tests only)
Carbon Monoxide	Annual Method 10 (can use RATA if at capacity)
NO_X (3 and 24-hr averages)	NO_X CEMS, O_2 or CO_2 diluent monitor, and flow device as needed
NO_X (performance)	Annual Method 20 (can use RATA if at capacity)

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E. Administrator, New Source Review Section
Teresa Heron, Review Engineer, New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

A A Linero, P.E.
for C. H. Fancy, P.E., Chief
Bureau of Air Regulation

Date: 7/10/98

Approved By:

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

Date: 7/10/98

REFERENCES

[1] Minutes of City of Lakeland Commission Meeting of October 26, 1997
[2] MPS Review. "Steam Cooled 60 Hz W501G Generates 230 MW, Modern Power Systems." August 1994.
[3] Minutes of City of Lakeland Commission Meeting of February 16, 1998
[4] Letter from Akita, E, Mitsubishi Heavy Industries, Ltd to Linero, A.A., Florida DEP. April 28, 1998. Gas Turbine 501G Question.
[5] Mitsubishi Heavy Industries. www.mhi.co.jp/annual/htm/mprod.html "Takasago 330-MW Demonstrator Combined Cycle Plant."
[6] Mitsubishi Heavy Industries. www.mhi.co.jp/tech/htm/e835101a.htm
[7] DOE Techline. "Major Test of Utility Turbine Compressor Sets Stage for Westinghouse to advance in DOE Turbine Program." October 14, 1996.
[8] Telecon. Swanson, D., GE, with Linero, A.A., DEP. Inquiry on GE turbine sizes. April, 1998.
[9] Westinghouse. "Combustion Technology Update - 501 G and Westinghouse Family of combustion turbines." March 30, 1998
[10] EPA`Region 2. PSD Permit, Eco-Electrica Cogeneration Project (Westinghouse 501F).
[11] New York State. PSD Permit, Sithe/IPP (GE 7FA).
[12] Telecon. Schorr, M., GE, and Costello, M., Florida DEP. March 31, 1998. Status of DLN2.6 Program.
[13] Letter from Santoro, J., Westinghouse Electric Corporation to Osbourn, S., Florida Power Corporation. ULN Development Schedule. April 14, 1998.
[14] DOE Website. www.fetc.doe.gov/products/power/ats. "Advanced Turbine Systems."
[15] DOE Website. www.fe.doe.gov/coal_power/ats_so. "Advanced Turbine Systems - Strategic objective."
[16] DOE Techline. "DOE, U.S. Turbine Developers poised to take Next Step Toward 21st Century." August 8, 1995.
[17] Westinghouse. "501G Application Overview."
[18] Diakunchak, I.S., Bannister, R.L., Huber, D.J., and Roan, D.F. "Technology Development Programs for the Advanced Turbine Systems engine." September 3, 1996.
[19] Letter from Gibson, J.L., Westinghouse Electric Corporation to Shelton, F., City of Lakeland. Ultra Low NO_X Combustion Technology. March 31, 1998.
[20] Snyder, R.B., "Alternative Control Techniques Document--NO_X Emissions from stationary Gas Turbines." EPA-453/R-93-007. January, 1993.
[21] SBE Environmental Company. PSD Application, Puerto Rico Electric Power Authority Proposed 248 MW Combustion Turbine Facility, Cambalache, Puerto Rico. January, 1994.
[22] Golder and Associates. Air Permit Application and PSD Analysis, City of Lakeland 501G Project. Table 4-2.
[23] Telecon. Claudio, F., EPA Region 2, CEPD, with Linero, A.A., Florida DEP. March 10, 1998. Status of PREPA Cambalache Project.
[24] EPA Region 2. PSD Permit, PREPA Cambalache Electric generating Facility. July 31, 1995.
[25] Letter from Booth, F.A., Engelhard to Kosky, K., Golder Associates. Budgetary Proposal 97616. November 10, 1997.
[26] Letter from Booth, F.A., Engelhard to Linero, A.A., Florida DEP. Budgetary Proposal EPB98154. April 10, 1998.

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

G.2 This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings or exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.

G.3 As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.

G.4 This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.

G.5 This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

G.6 The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.

G.7 The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

a) Have access to and copy and records that must be kept under the conditions of the permit;
b) Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
c) Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

Reasonable time may depend on the nature of the concern being investigated.

G.8 If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

a) A description of and cause of non-compliance; and
b) The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

G.9 In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extend it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.

G.10 The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

G.11 This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

G.12 This permit or a copy thereof shall be kept at the work site of the permitted activity.

G.13 This permit also constitutes:

a) Determination of Best Available Control Technology (X)
b) Determination of Prevention of Significant Deterioration (X); and
c) Compliance with New Source Performance Standards (X).

G.14 The permittee shall comply with the following:

a) Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.

b) The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.

c) Records of monitoring information shall include:

1. The date, exact place, and time of sampling or measurements;
2. The person responsible for performing the sampling or measurements;
3. The dates analyses were performed;
4. The person responsible for performing the analyses;
5. The analytical techniques or methods used; and
6. The results of such analyses.

G.15 When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

2. Regulated or Unregulated Emissions Unit? (Check one)

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

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

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

Unregulated Emissions – Tank 1.05 million gallons

4. Emissions Unit Identification Number: [ ] No ID
ID: **029** [ ] ID Unknown

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

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

This emission unit information section addresses a 1.05 million gallon tank as an unregulated emission unit. NSPS subpart Kb recordkeeping requirements are applicable; there is no emission limiting or work practice standards.

Emissions Unit Control Equipment

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

Emissions Unit Details

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

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

Segment Description and Rate: Segment 1 of 1

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **No. 2 Distillate Oil/Diesel**		
2. Source Classification Code (SCC): **A2505030090**	3. SCC Units: **1,000 gallons**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: **4,251**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): **Annual rate based on inputs to Unit 5.**		

Segment Description and Rate: Segment _____ of _____

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

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
VOC			NS