LAKELAND ELECTRIC

Farzie Shelton, chE; REM
Manager of Environmental Affairs

April 29, 2003

RECEIVED
APR 30 2003
BUREAU OF AIR REGULATION

Mr. Scott M. Sheplak, P.E.; Administrator
Department of Environmental Protection
Division of Air Resources Management
Title V Section
Twin Towers Office Building
2600 Blair Stone Road, Mail Station #5505
Tallahassee, Florida 32399-2400

Re: C. D. McIntosh Power Plant - Facility Identification Number 1050004
Title V Permit Renewal Permit Application

Dear Mr. Sheplak:

The above Title V operating permit renewal application falls due on July 31, 2003. Therefore, enclosed please find four copies of this application signed by Mr. Ken Kosky P.E. of Golder Associates and Certified by Mr. Timothy Bates our Responsible Official. This application has been prepared in accordance with the Rule 62-210 and instructions associated with the Form No. 62-210.900(1). As per our telephone discussion of April 25, 2003 and your confirmation, we have utilized Attachment MC-FL-C15 "Compliance Certification" as required for this application.

If you should have any questions, please do not hesitate to contact me.

Sincerely,

Farzie Shelton

Enc.

City of Lakeland ◦ Department of Electric Utilities

501 East Lemon Street ◦ Lakeland, Fl 33801-5050 ◦ (863) 834-6603 ◦ Fax (863) 834-8187 ◦ Message System 834-6592

farzie.shelton@lakelandgov.net

RECEIVED

APR 30 2003

BUREAU OF AIR REGULATION

TITLE V OPERATION PERMIT APPLICATION FOR C.D. MCINTOSH, JR. POWER PLANT LAKELAND ELECTRIC POLK COUNTY, FLORIDA

Prepared For:
Lakeland Electric – Power Supply
City of Lakeland
501 East Lemon Street
Lakeland, Florida 33801

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

April 2003
0237622

DISTRIBUTION:
4 Copies - FDEP
2 Copies - Lakeland Electric – Environmental Affairs
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 ☒ No

6. Existing Permitted Facility?
☒ Yes ☐ No

Application Contact

1. Name and Title of Application Contact:
Ms. Farzie Shelton, Manager of Environmental Affairs

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: (**863**) **834 – 6603** Fax: (**863**) **834 - 8187**

Application Processing Information (DEP Use)

1. Date of Receipt of Application:	4-30-2003
2. Permit Number:	1050004-016-AV
3. PSD Number (if applicable):	
4. Siting Number (if applicable):	

Purpose of Application

Air Operation Permit Application

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

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

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

Current construction permit number:________________

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

Current construction permit number:________________

Operation permit number to be revised: ________________

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

Operation permit number to be revised/corrected: ________________

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

Operation permit number to be revised: **1050004-011-AV Permit Renewal**

Reason for revision: **Title V Renewal**

Air Construction Permit Application

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

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

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

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

*** Current Permit No. 1050004-04-AC (PSD-FL-245) extended to March 31, 2003 and reflects Permit Amendment No. 1050004-010-AC (PSD-FL-245C)**

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official:
Timothy C. Bates, Director of Energy Supply

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: (**863**) **834 - 6541** Fax: (**863**) **834 - 6362**

4. Owner/Authorized Representative or Responsible Official Statement:

I, the undersigned, am the owner or authorized representative(check here [ ], if so) or the responsible official (check here [* **X** *], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.*

Timothy C Bates 4/29/03
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**

***Board of Professional Engineers Certificate of Authorization #00001670**

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 [X], if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Kennard F. Kosky
Signature

4/22/03
Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
001	McIntosh Unit 1		
005	McIntosh Unit 2		
006	McIntosh Unit 3		
002,003	Diesel Engine Peaking Units 2 and 3		
004	Gas Turbine Peaking Unit 1		
028	McIntosh Unit 5; W501G Combustion Turbine		
--	Mechanical Draft Cooling Tower		
--	Material Handling		
007, 008, 009, 010, 011, 012, 013, 014, 016, 017, 018, 019, 020, 021, 022, 023, 024, 025, 026, 027, 029	Unregulated Emission Activities (See Attachment MC-FI-C12)		

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

Pursuant to Florida Administrative Code (F.A.C.) Chapter 62-213, this application is to renew the C.D. McIntosh Power Plant Title V Operation Permit No. 1050004-011-AV. The Title V permit expiration date is December 31, 2003, and the renewal application due date is July 5, 2003. See Attachment MC-FI-C1 for photos of the facility.

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): **28 / 4 / 50** Longitude (DD/MM/SS): **81 / 55 / 32**

3. Governmental Facility Code:	4. Facility Status Code:	5. Facility Major Group SIC Code:	6. Facility SIC(s):
4	**A**	**49**	**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, 1 gas turbine peaking unit, and 1 combustion turbine operating in combined cycle (Unit 5). 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. Unit 5 consists of a Westinghouse 501G combustion turbine that is primarily fired with natural gas with distillate oil as backup, heat recovery steam generator, and steam electric generator.

Facility Contact

1. Name and Title of Facility Contact:
Ms. Farzie Shelton, Manager of Environmental Affairs

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: (**863**) **834 – 6603** Fax: (**863**) **603 - 8187**

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 1, Unit 2, Unit 3, and Unit 5 are regulated under Acid Raid, Phase II,
Unit 2 is subject to NSPS Subpart D,
Unit 3 is subject to NSPS Subpart D, and
Unit 5 is subject to NSPS Subpart GG.

List of Applicable Regulations

The facility regulations identified in the Title V permit (Final Permit No. 10150004-011-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
PM	**A**				
PM_{10}	**A**				
VOC	**A**				
SO_2	**A**				
H106	**A**				
NO_X	**A**				
HAPs	**A**				
CO	**A**				
HCl	**A**				

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location:
[X] Attached, Document ID: MC-FI-C1 [ ] Not Applicable [ ] Waiver Requested

2. Facility Plot Plan:
[X] Attached, Document ID: MC-FI-C2 [ ] Not Applicable [ ] Waiver Requested

3. Process Flow Diagram(s):
[X] Attached, Document ID: MC-FI-C3 [ ] Not Applicable [ ] Waiver Requested

4. Precautions to Prevent Emissions of Unconfined Particulate Matter:
[X] Attached, Document ID: MC-FI-C4 [ ] Not Applicable [ ] Waiver Requested

5. Fugitive Emissions Identification:
[X] Attached, Document ID: MC-FI-C5 [ ] Not Applicable [ ] Waiver Requested

6. Supplemental Information for Construction Permit Application:
[ ] Attached, Document ID: ______ [X] Not Applicable

7. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities:
[X] Attached, Document ID: MC-FI-C8 [ ] 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:
[X] Attached, Document ID: MC-FI-C12 [ ] Not Applicable

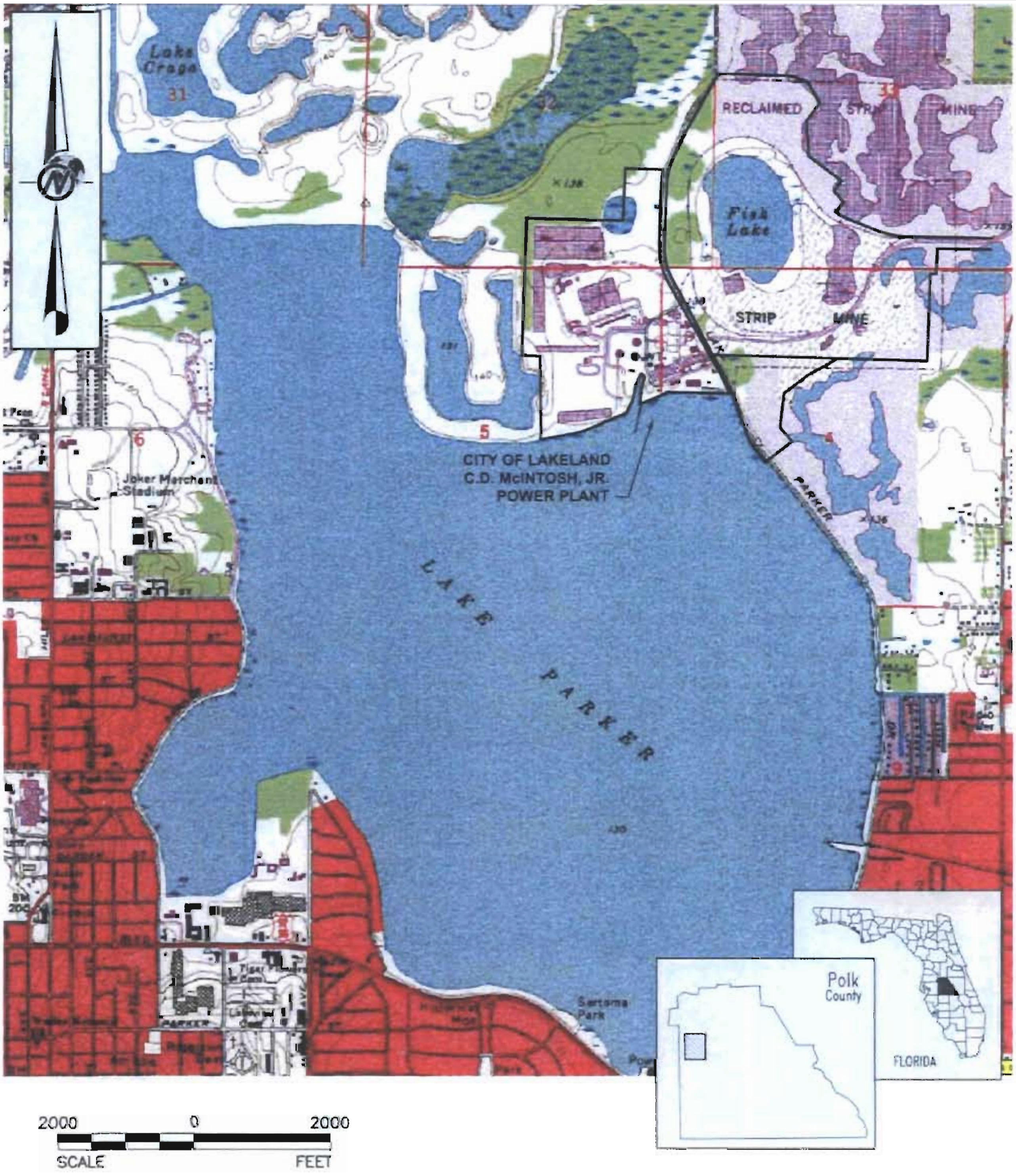
13. Risk Management Plan Verification:
[X] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID: MC-FI-C13) or previously submitted to DEP (Date and DEP Office: December 27, 2001)
[ ] Plan to be submitted to CEPPO (Date required:____________________)
[ ] Not Applicable

14. Compliance Report and Plan:
[X] Attached, Document ID: MC-FI-C14[ ] Not Applicable

15. Compliance Certification (Hard-copy Required):
[X] Attached, Document ID: MC-FI-C15[ ] Not Applicable

ATTACHMENT MC-FI-C1

AREA MAP SHOWING FACILITY LOCATION AND FACILITY PHOTOGRAPHS



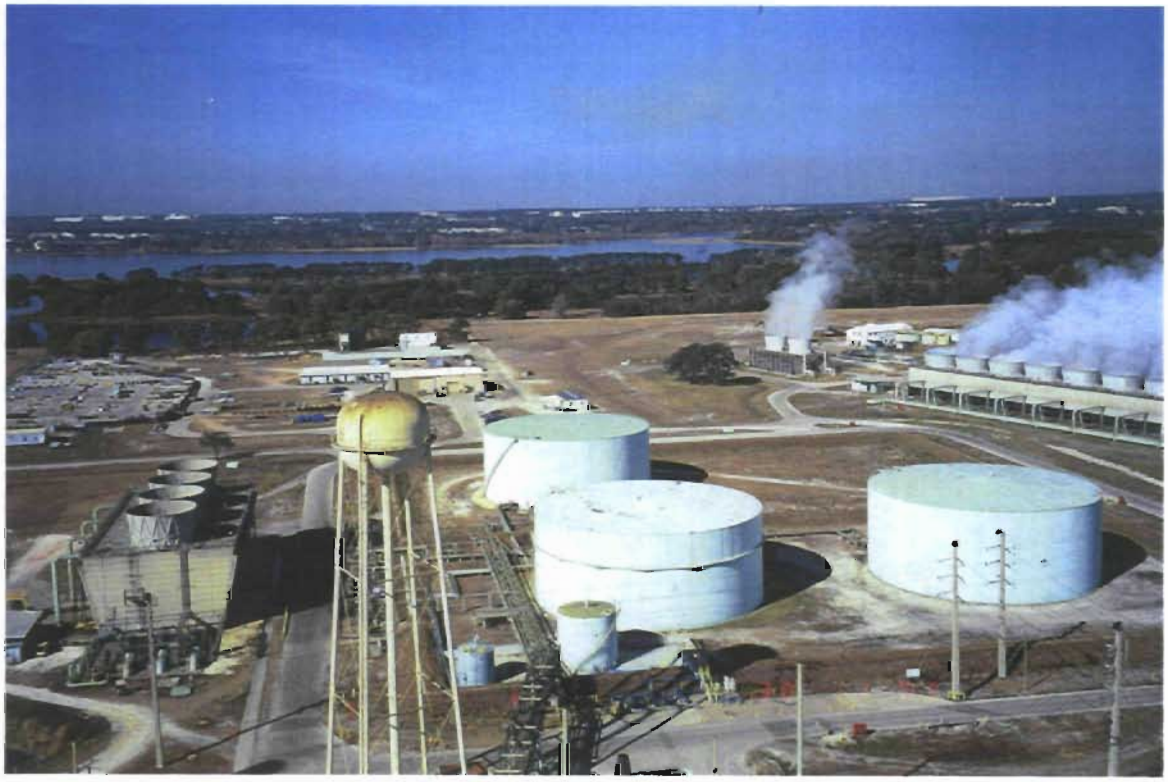
REFERENCES

1.) USGS TOPOGRAPHIC MAP, 7.5 MIN. QUADRANGLE MAP SERIES: LAKELAND QUADRANGLE, POLK COUNTY, FLORIDA.

Attachment MC-FI-C1
Area Map Showing Facility Location

Source: Golder Associates Inc., 2002

Golder Associates




30 1 '03


30 1 '03

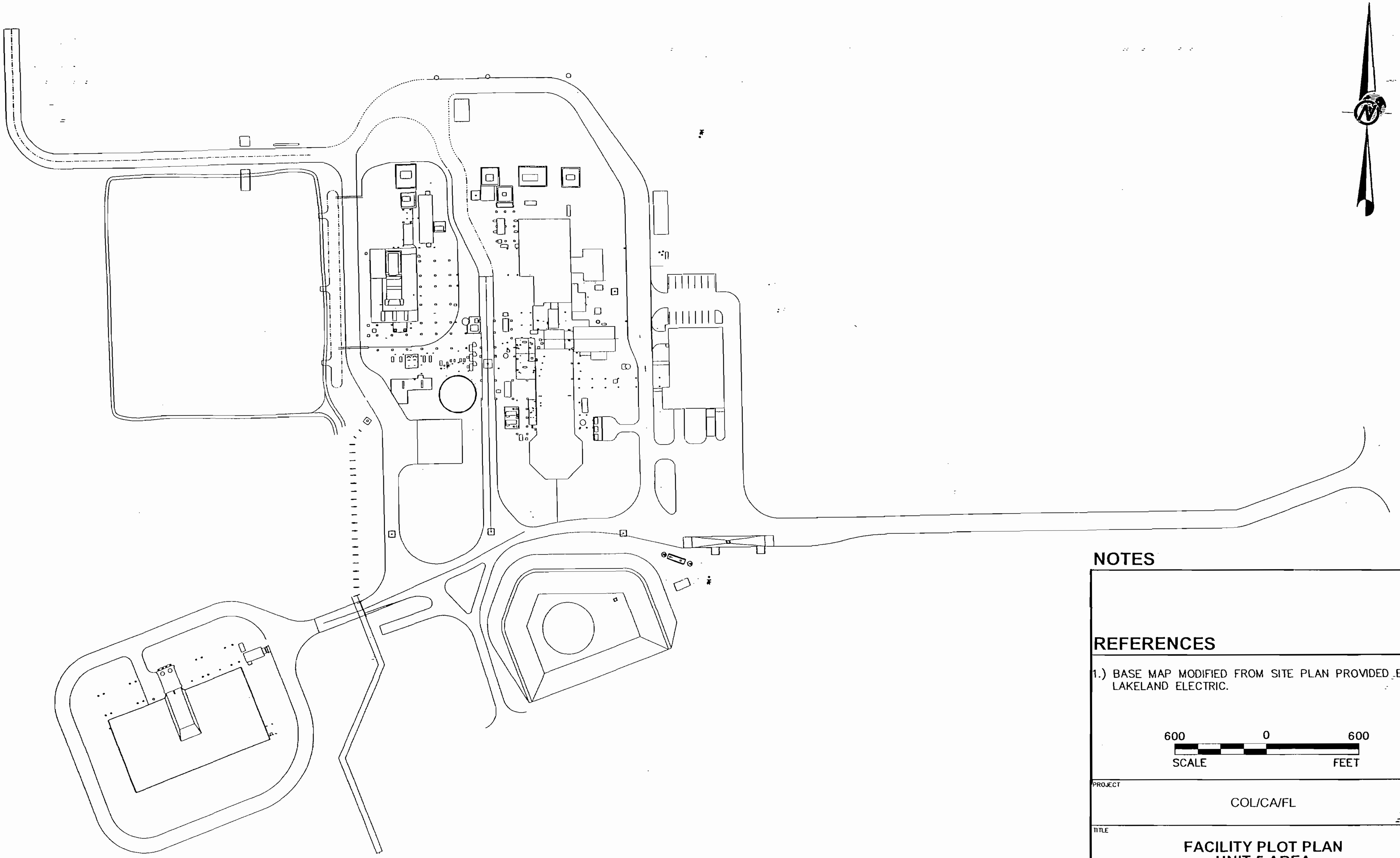

30 1 '03


20 1 '03


20 1 '03

ATTACHMENT MC-FI-C2

FACILITY PLOT PLAN



NOTES

REFERENCES

1.) BASE MAP MODIFIED FROM SITE PLAN PROVIDED BY LAKELAND ELECTRIC.

600 0 600
SCALE FEET

PROJECT

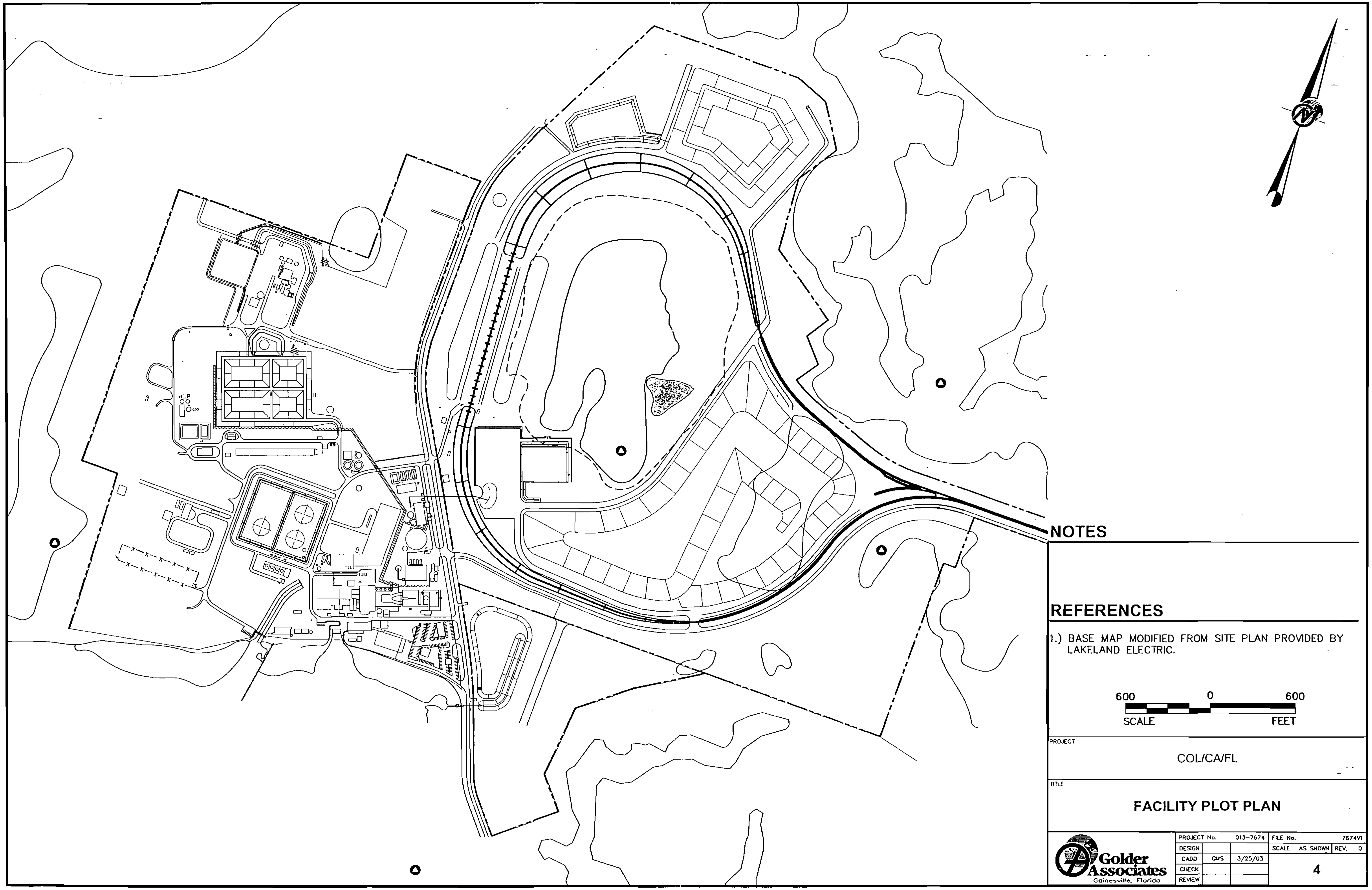
COL/CA/FL

TITLE

FACILITY PLOT PLAN
UNIT 5 AREA

Golder Associates
Gainesville, Florida

PROJECT No.		013–7674	FILE No.	7674V1
DESIGN			SCALE AS SHOWN	REV. 0
CADD	GMS	3/25/03	4	
CHECK				
REVIEW				



NOTES

REFERENCES

1.) BASE MAP MODIFIED FROM SITE PLAN PROVIDED BY LAKELAND ELECTRIC.

600 0 600

SCALE FEET

PROJECT

COL/CA/FL

TITLE

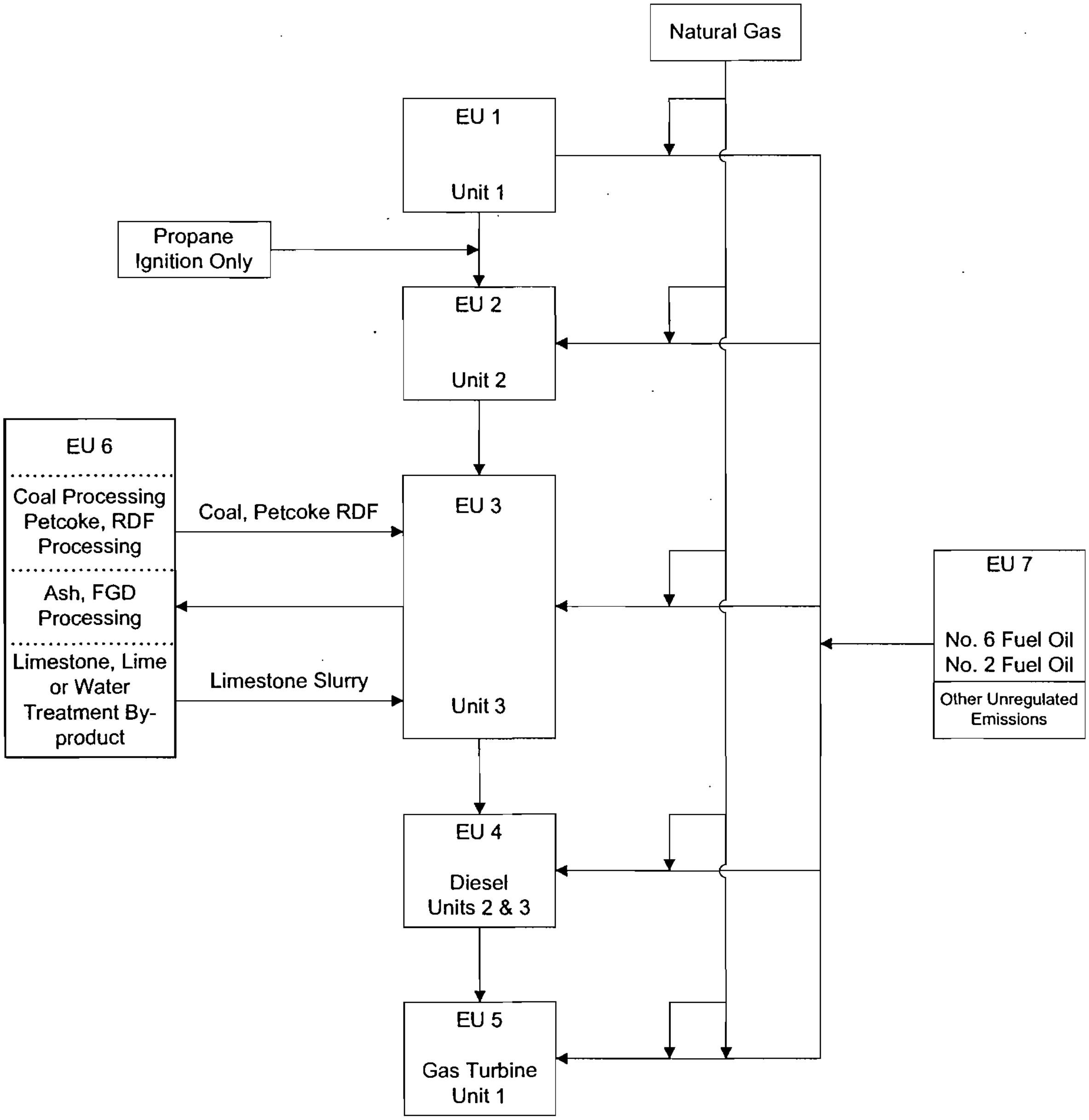
FACILITY PLOT PLAN

Golder Associates
Gainesville, Florida

PROJECT No.		013–7674	FILE No.	7674V1
DESIGN			SCALE AS SHOWN	REV. 0
CADD	GMS	3/25/03	4	
CHECK				
REVIEW				

ATTACHMENT MC-FI-C3

PROCESS FLOW DIAGRAM



Attachment MC-FI-C3
McIntosh Facility
Process Flow Diagram
Lakeland Electric & Water Utilities
Lakeland, Florida

Process Flow Legend

Material Flow ⟶

Filename:
0237622/4/4.4/4.4.1 McIntosh/
MC-FI-C3.vsd

Date: 04/15/03

Golder
Associates

ATTACHMENT MC-FI-C4

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

ATTACHMENT MC-FI-C4

PRECAUTIONS TO PREVENT EMISSIONS OF UNCONFINED PARTICULATE MATTER

The facility has small amounts of unconfined particulate matter as a result of the operation of the facility. The particulate matter includes:

- Fugitive dust from paved and unpaved roads,
- Fugitive particulates from the use of bagged chemical products
- Coal handling and storage
- Limestone handling and storage
- FGD/ash by-products/handling and storage
- Municipal solid waste
- Ash cleaning
- Paint removal

Operational measures are undertaken at the facility which also minimize particulate emissions, in accordance with 62-296.320(4)(c), F.A.C. (Condition 8, Section II, Title V Permit):

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

ATTACHMENT MC-FI-C5

FUGITIVE EMISSIONS IDENTIFICATION

ATTACHMENT MC-FI-C5

FUGITIVE EMISSIONS IDENTIFICATION

Many fugitive emissions at the plant site have been classified as either "insignificant," or are exempt under Rule 62-213.430(b). The types of fugitive emissions that are included as insignificant or exempt are discussed below.

Criteria and Precursor Air Pollutants

Fugitive particulate emissions are addressed in Attachment MC-FI-J4. COL is not aware of fugitive emission of sulfur dioxide, nitrogen oxides, carbon monoxide, or lead compounds that would exceed the thresholds defined in the permit application instructions.

Volatile Organic Compounds (VOCs)

Fugitive emissions of VOCs include those resulting from the use of cleaners and solvents for maintenance and operation. VOCs are also emitted by the various fuel oil storage tanks on the plant property, and by the combustion turbines and the fossil-fuel steam generators. VOC emissions for storage tanks are covered in the facility-wide fugitive ***Emission Unit*** section of this permit application.

Fugitive HAPs Emissions

The following hazardous air pollutants are or may be present on the facility property and are potential sources of fugitive HAPs emissions:

- asbestos
- benzene
- chlorine
- hydrazine
- hydrochloric acid
- mercury compounds
- methyl ethyl ketone
- toluene
- xylene

Asbestos - Present in gasket material, pipe insulation, and various other locations. The facility complies with the federal NESHAPS (40 CFR 61 Subpart M) and state rules (62-257, F.A.C.) governing the abatement of asbestos-containing materials. No releases of asbestos are expected for the facility.

Benzene - Present in unleaded gasoline. The facility maintains a storage tank for unleaded gasoline. These emissions have been calculated to be significantly less than 1 TPY.

Chlorine - Used for water treatment at the facility.

Hydrazine - Hydrazine solution may be used for the treatment of boiler water.

Hydrochloric Acid - The facility may utilize hydrochloric acid in cleaning filter beds in the water treatment facility at the chemistry laboratory for use in analytical procedures.

Mercury Compounds - The facility uses mercury-containing compounds in the chemistry laboratory for use in analytical procedures and flow-measuring equipment.

Methyl Ethyl Ketone, Toluene, Xylene - The facility uses paint thinners and solvents (which may contain MEK, toluene, or xylene) for use in plant maintenance activities. These containers are kept closed.

Regulated Toxic or Flammable Substances

The following regulated toxic or flammable substances are or may be present at the facility:

- ammonia (aqueous, concentration 20% or greater)
- chlorine
- hydrazine
- hydrochloric acid
- nitric acid
- acetylene
- methane (natural gas)

Ammonia - Used for boiler water treatment.

Chlorine, Hydrazine, Hydrochloric Acid - Considered on the preceding page.

Nitric Acid - Nitric acid may be used in the chemistry laboratory for use in analytical procedures.

Acetylene - Present on the facility property in 250-lb cylinders which are used for plant maintenance (welding and cutting).

Methane - Is a primary component of natural gas. The facility has a natural gas pipeline which delivers fuel to the generating units. This fuel delivery system is normally airtight, but does have safety valves which occasionally relieve (open) when an overpressure condition develops in the gas line.

ATTACHMENT MC-FI-C8

LIST OF INSIGNIFICANT ACTIVITIES

ATTACHMENT MC-FI-C8

LIST OF INSIGNIFICANT ACTIVITIES

1. Sources exempt by Rule 62-210.300(3)(a)
   62-210.300(3)(a)4.- comfort heating < 1 mmBtu/hr
   62-210.300(3)(a)5.- mobile sources
   62-210.300(3)(a)7.- non-industrial vacuum cleaning
   62-210.300(3)(a)8.- refrigeration units
   62-210.300(3)(a)9.- vacuum pumps for labs
   62-210.300(3)(a)10.- steam cleaning equipment
   62-210.300(3)(a)11.- sanders < 5 ft^2
   62-210.300(3)(a)12.- space heating equip.; (non-boilers)
   62-210.300(3)(a)14.- bakery ovens
   62-210.300(3)(a)15.- laboratory equipment
   62-210.300(3)(a)16.- brazing, soldering or welding
   62-210.300(3)(a)17.- laundry dryers
   62-210.300(3)(a)22.- fire and safety equipment
   62-210.300(3)(a)24.- surface coating <5% VOC

2. Storage Tanks: exempt by Rule 62-210.300(3)(b)
   Diesel Storage Tank(T-021), Total losses = 262.2 lb/yr, Title V Air Operating Premit Application(6/11/96)
   Heavy Oil Tank(T-113), Total losses = 63.7 lb/yr, Title V Air Operating Premit Application(6/11/96)
   Heavy Oil Tank(T-114), Total losses = 63.7 lb/yr, Title V Air Operating Premit Application(6/11/96)
   Heavy Oil Tank(T-115), Total losses = 63.7 lb/yr, Title V Air Operating Premit Application(6/11/96)
   Used Oil Tank(T-116), Total losses = 88.9 lb/yr, Title V Air Operating Premit Application(6/11/96)

Reference: Condition 5, Section II, Title V Permit

ATTACHMENT MC-FI-C12

IDENTIFICATION OF ADDITIONAL APPLICABLE REQUIREMENTS

Lakeland Electric
C. D. McIntosh, Jr. Power Plant
Facility ID No.: 1050004
Polk County

Title V Air Operation Permit Revision
FINAL Title V Permit Revision No.: 1050004-011-AV

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

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

Telephone: 850/488-1344
Fax: 850/922-6979

Compliance Authority:
Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

Title V Air Operation Permit Revision
FINAL Title V Permit Revision No.: 1050004-011-AV
Table of Contents

Section **Page Number**

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

FINAL Title V Permit Revision No.: 1050004-011-AV
Facility ID No.: 1050004
SIC Nos.: 49, 4911
Project: Title V Air Operation Permit Revision

This permit revision is for the increase of the maximum heat input of Unit No. 5, a simple cycle stationary combustion turbine, when combusting natural gas for the C. D. McIntosh, Jr. Power Plant. Unit No. 5 is an Acid Rain unit. This facility is located at 3030 East Lake Parker Drive, Lakeland, Polk County; UTM Coordinates: Zone 17, 409.0 km East and 3106.2 km North; Latitude: 28° 04' 50" North and Longitude: 81° 55' 32" West.

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

Referenced attachments made a part of this permit:

Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Appendix TV-3, Title V Conditions (version dated 04/30/99)
APPENDIX SS-1, STACK SAMPLING FACILITIES (version dated 10/07/96)
TABLE 297.310-1, CALIBRATION SCHEDULE (version dated 10/07/96)
FIGURE 1 - SUMMARY REPORT-GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE REPORT (40 CFR 60; July 1996)
Phase II Acid Rain Application/Compliance Plan received 12/18/95
Phase II Acid Rain Application/Compliance Plan received 3/10/98
Alternate Sampling Procedure: ASP Number 97-B-01
Appendix 40 CFR 60 Subpart A - General Provisions (version dated 07/23/97)
Phase I/II NO_X Acid Rain Application/Compliance Plan received December 9, 1997
Statement of Basis
Appendix H-1, Permit History / ID Number Changes
W501G McIntosh #5, Lakeland FL – Maximum Heat Input as a Function of Compressor Inlet Temperature (1/5/01)

Effective Date: January 1, 1999
Title V Permit Revision Effective Date: October 16, 2001
Renewal Application Due Date: July 5, 2003
Expiration Date: December 31, 2003

Howard L. Rhodes, Director
Division of Air Resources
Management

HLR/sms/es

Section I. Facility Information.

Subsection A. Facility Description.

This facility consists of three fossil fuel fired steam generators, two diesel powered generators, and two gas turbines. Fossil fuel fired steam generators 1 and 2 are fired with No. 6 fuel oil and natural gas with distillate oil used as an ignitor. Fossil fuel fired steam generator 3 is primarily fired with coal, refuse derived fuel and petroleum coke. Gas Turbine Peaking Unit 1 is primarily fired with natural gas, or No. 2 fuel oil with a maximum sulfur content of 0.5 percent by weight. McIntosh Unit 5, a 250 MW simple cycle stationary combustion turbine, fired with natural gas, or No. 2 or superior grade fuel oil with a maximum sulfur content of 0.05 percent by weight.

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

Based on the initial Title V permit application received June 14, 1996 and the application for the revision to the Title V permit dated April 24, 2000, this facility is a major source of hazardous air pollutants (HAPs).

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

E.U. ID No.	Brief Description
-001	McIntosh Unit 1 - Fossil Fuel Fired Steam Generator
-002	Diesel Engine Peaking Unit 2
-003	Diesel Engine Peaking Unit 3
-004	Gas Turbine Peaking Unit 1
-005	McIntosh Unit 2 - Fossil Fuel Fired Steam Generator
-006	McIntosh Unit 3 - Fossil Fuel Fired Steam Generator
-028	McIntosh Unit 5 – 250 MW Simple Cycle Stationary Combustion Turbine

Unregulated Emissions Units and/or Activities

E.U. ID No.	**Brief Description of Emissions Units and/or Activity**
-007	Tanks with greater than 10,000 gallon capacity installed prior to July 23, 1984
-008	Diesel drive coal tunnel sump engine
-009	Fire water UPS diesel No. 31
-010	Fire water UPS diesel No. 32
-011	CT startup diesel
-012	General purpose diesel engines
-013	Emergency generators
-014	General purpose painting
-015	Parts Cleaning
-016	Sand Blasting (Maintenance only)
-017	Wastewater Treatment Tank
-018	Three Cooling Towers (Unit 2 and 3)
-019	Northside Waste Water Treatment Facility - Wastewater treatment processes and tanks
-020	Northside Waste Water Treatment Facility - Two emergency diesel generators
-021	Northside Waste Water Treatment Facility - Chemical and petroleum storage
-022	Northside Waste Water Treatment Facility - Miscellaneous activities
-023	Coal processing and conveying system
-024	Coal storage system
-025	Coal transfer and loading system
-026	Limestone handling and storage system
-027	Flyash handling and storage system
-029	1.05 million gallon storage tank for McIntosh Unit 5, subject only to the reporting requirements of 40CFR60, Subpart Kb

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

Subsection C. Relevant Documents.

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

These documents are provided to the permittee for information purposes only:
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements
Appendix A-1, Abbreviations, Acronyms, Citations, and Identification Numbers

These documents are on file with permitting authority:
Initial Title V Permit Application received June, 14, 1996
Additional Information Request dated January 13, 1997
Additional Information Response received February 10, 1997
Additional Information received May 9, 1997
Letter received July 2, 1997 from Ms. Farzie Shelton
Additional Information received July 8, 1997
Letter received August 7, 1997 from Ms. Farzie Shelton
Letter received September 4, 1997 from Ms. Farzie Shelton
Title V Permit Revision Application received April 24, 2000
Letter received August 18, 2000 from Ms. Farzie Shelton

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

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

2. Not Federally Enforceable General Pollutant Emission Limiting Standards. Objectionable Odor Prohibited. The permittee shall not cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.
[Rule 62-296.320(2), F.A.C.]

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

4. Prevention of Accidental Releases (Section 112(r) of CAA).
a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable; and,
b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.
[40 CFR 68]

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

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

7. General Pollutant Emission Limiting Standards. Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. Containers shall be kept closed.
[Rule 62-296.320(1)(a), F.A.C.; Proposed by applicant in the initial Title V permit application received June 14, 1996; Revised by a letter received August 7, 1997]

8. Reasonable precautions to prevent emissions of unconfined particulate matter at this facility include: maintenance of paved areas; regular mowing of grass and care of vegetation; and limiting access to plant property by unnecessary vehicles.
[Rule 62-296.320(4)(c)2., F.A.C.; Proposed by applicant in the initial Title V permit application received June 14, 1996, as amended in a request received July 8, 1997]

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

10. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3), F.A.C., shall be submitted within 60 (sixty) days after the end of the calendar year. {See condition 51., APPENDIX TV-3, TITLE V CONDITIONS}
[Rule 62-214.420(11), F.A.C.]

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

Department of Environmental Protection
Southwest District Office
3804 Coconut Palm Drive
Tampa, Florida 33619-8218
Telephone: 813/744-6100
Fax: 813/744-6084

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

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

III. Emissions Section Unit.

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

E.U. ID No.	Brief Description
-001	McIntosh Unit 1 - Fossil Fuel Fired Steam Generator

McIntosh Unit 1 is a forced draft boiler rated at a nominal load of 90 megawatts. The unit is fired with natural gas at a maximum heat input rate of 985 million Btu per hour (approximately 970 million cubic feet per hour), or No. 6 fuel oil, having a maximum sulfur content of 2.5 percent by weight, at a maximum heat input rate of 950 million Btu per hour (approximately 6,300 gallons per hour). This unit is also permitted to burn "on-specification" used oil generated by the City of Lakeland, at a maximum heat input rate of 950 million Btu per hour. McIntosh Unit 1 began commercial service in February, 1971.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; and Rule 62-296.405, F.A.C., Fossil Fuel Steam Generators with More than 250 million Btu per Hour Heat Input.}

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
1	985	Natural Gas
	950	No. 6 Fuel Oil
	950	Used Oil

When a blend of fuel oil, "on-specification" used oil or natural gas is fired, the heat input is prorated based on the percent heat input of each fuel. The Acid Rain CEM will not be a method of compliance for the determination of the heat input rate.
[Rules 62-4.160(2), 62-210.200(PTE) and 62-296.405, F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}

A.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **A.23.**
[Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation. Fuels. The only fuels allowed to be burned are natural gas, propane, No. 6 Fuel Oil, On-Specification Used Oil, No. 2 Fuel Oil and combinations of natural gas, propane, No. 6 Fuel Oil, No. 2 Fuel Oil and/or On-Specification Used Oil. On-Specification used oil containing any quantifiable levels of PCBs can only be fired when the emissions unit is at normal operating temperatures.
[Rule 62-213.410, F.A.C.; and, 40 CFR 271.20(e)(3)]

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

Emission Limitations and Standards

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

A.5. Visible Emissions. Visible emissions shall not exceed 20 percent opacity, except for one two-minute period per hour during which opacity shall not exceed 40 percent. Emissions units governed by this visible emissions limit shall compliance test for particulate matter emissions annually and as otherwise required by Chapter 62-297, F.A.C.
[Rule 62-296.405(1)(a), F.A.C.]

A.6. Visible Emissions - Soot Blowing and Load Change. Visible emissions shall not exceed 60 percent opacity during the 3-hours in any 24 hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more.
[Rule 62-210.700(3), F.A.C.]

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

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

A.9. Sulfur Dioxide. When burning liquid fuel, sulfur dioxide emissions shall not exceed 2.75 pounds per million Btu heat input , as measured by applicable compliance methods.
[Rule 62-296.405(1) (c)1.j., F.A.C.]

A.10. Sulfur Dioxide - Sulfur Content. The No. 6 fuel oil sulfur content shall not exceed 2.5 percent, by weight. See specific condition **A.21.**
[Rule 62-296.405(1)(e)3., F.A.C.; and, AO 53-243945]

A.11. "On-Specification" Used Oil. Only "on-specification" used oil generated by the City of Lakeland shall be fired in this unit. The quantity fired in this unit shall not exceed 1,000 barrels (42,000 gallons) per calendar year. "On-specification" used oil is defined as used oil that meets the 40 CFR 279 (Standards for the Management of Used Oil) specifications listed below. Used oil that does not meet all of the following specifications is considered "off-specification" oil and shall not be fired.

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

* As determined by ASTM Standard D140-70, or equivalent
[40 CFR 279.11; and, AO 53-243945]

Excess Emissions

A.12. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

A.13. Excess emissions resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.
[Rule 62-210.700(2), F.A.C.]

A.14. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

A.15. Sulfur Dioxide. **The permittee elected to demonstrate compliance by accepting a liquid fuel sulfur limit that will be verified with a fuel analysis provided by the vendor or the permittee upon each fuel delivery.** This protocol is allowed because the emissions unit does not have an operating flue gas desulfurization device. See specific conditions **A.10., A.20. and A.21.**
[Rule 62-296.405(1)(f)1.b., F.A.C.]

A.16. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

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

A.17. Visible emissions. The test method for visible emissions shall be DEP Method 9, incorporated in Chapter 62-297, F.A.C. A transmissometer may be used and calibrated according to Rule 62-297.520, F.A.C. See specific condition **A.18.**
[Rule 62-296.405(1)(e)1., F.A.C.]

A.18. DEP Method 9. The provisions of EPA Method 9 (40 CFR 60, Appendix A) are adopted by reference with the following exceptions:

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

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

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

A.20. Sulfur Dioxide. The test methods for sulfur dioxide emissions shall be EPA Methods 6, 6A, 6B, or 6C, incorporated by reference in Chapter 62-297, F.A.C. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated into the operation permit for the emissions unit. If the emissions unit obtains an alternate procedure under the provisions of Rule 62-297.620, F.A.C., the procedure shall become a condition of the emissions unit's permit. The Department will retain the authority to require EPA Method 6 or 6C if it has reason to believe that exceedences of the sulfur dioxide emissions limiting standard are occurring. Results of an approved fuel sampling and analysis program shall have the same effect as EPA Method 6 test results for purposes of demonstrating compliance or noncompliance with sulfur dioxide standards. **The permittee may use the EPA test methods, referenced above, to demonstrate compliance; however, as an alternate sampling procedure authorized by permit, the permittee elected to demonstrate compliance by accepting a liquid fuel sulfur limit that will be verified with a fuel analysis provided by the vendor or the permittee upon each fuel delivery.** See specific conditions **A.10. and A.21.**
[Rules 62-213.440, 62-296.405(1)(e)3. and 62-297.401, F.A.C.; and, AO 53-243945]

A.21. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91, or the respective successor ASTM method(s).
[Rules 62-213.440, 62-296.405(1)(e)3., 62-296.405(1)(f)1.b. and 62-297.440, F.A.C.]

A.22. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

A.23. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

A.24. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

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

A.26. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

A.27. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid for more than 400 hours other than during startup.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   a. Did not operate; or
   b. In the case of a fuel burning emissions unit, burned liquid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   a. Visible emissions, if there is an applicable standard;
   b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
   c. Each NESHAP pollutant, if there is an applicable emission standard.

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

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

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.
(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.; and, SIP approved]

A.28. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
[Rule 62-297.310(7)(a)4., F.A.C.]

A.29. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
[Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

A.30. Compliance with the "on-specification" used oil requirements will be determined as follows:
(a) Analysis of a sample collected from each batch delivered for firing; or,
(b) The new batch delivery is from a collection site that has an acceptable analysis already on file with the facility and the analytical results are assumed by the facility for the batch.

For quantification purposes, the highest concentration of each constituent as determined by any analysis is assumed to be the concentration of the constituent of the blended used oil.
See specific condition **A.11.**
[AO 53-243945]

Record keeping and Reporting Requirements

A.31. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department or the appropriate Local Program in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department or the appropriate Local Program.
[Rule 62-210.700(6), F.A.C.]

A.32. Submit to the Department a written report of emissions in excess of emission limiting standards as set forth in Rule 62-296.405(1), F.A.C., for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rules 62-213.440 and 62-296.405(1)(g), F.A.C.]

A.33. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

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

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

A.34. Records shall be kept of each delivery of "on-specification" used oil with a statement of the origin of the used oil and the quantity delivered/stored for firing. In addition, monthly records shall be kept of the quantity of "on-specification" used oil fired in this unit. The above records shall be maintained in a form suitable for inspection, retained for a minimum of five years, and be made available upon request.
[Rule 62-213.440(1)(b)2.b., F.A.C.; and, AO 53-243945]

A.35. The permittee shall include in the "Annual Operating Report for Air Pollutant Emitting Facility" a summary of the "on-specification" used oil analyses for the calendar year and a statement of the total quantity of "on-specification" used oil fired in Unit 1 during the calendar year.
[AO 53-243945]

Section III. Emissions Unit(s) and Conditions.

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

E.U. ID No.	Brief Description
-002	Diesel Engine Peaking Unit 2
-003	Diesel Engine Peaking Unit 3

Diesel Engine Peaking Units 2 and 3 are diesel fired internal combustion engines which each drives a generator capable of producing electric power at a maximum rating of 2.5 megawatts. These units are each fired on No. 2 fuel oil, with a maximum sulfur content of 0.5 percent by weight, at a maximum firing rate of 201.6 gallons per hour. This corresponds to a maximum heat input of 28 million Btu per hour. Diesel Engine Peaking Units 2 and 3 began commercial service in 1970.

{Permitting note(s): The emissions units are regulated under Rule 62-210.300, F.A.C., Permits Required. Each diesel engine peaking unit has its own stack.}

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

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity.
a. The maximum heat input rate of each diesel engine peaking unit is 28 million Btu per hour
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]
b. **Not Federally Enforceable** The maximum firing rate of each diesel engine peaking unit is 201.6 gallons per hour firing No. 2 fuel oil.
[AO 53-244726]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}

B.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **B.13.**
[Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation - Fuels. Only distillate (No. 2) fuel oil shall be fired in the diesel engine peaking units.
[Rule 62-213.410, F.A.C.]

B.4. Hours of Operation. These emissions units may operate continuously, i.e., 8,760 hours/year.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AO 53-244726]

Emission Limitations and Standards

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

B.5. Visible Emissions. Visible emissions from each diesel engine peaking unit shall not be equal to or greater than 20 percent opacity.
[Rule 62-296.320(4)(b)1., F.A.C.; and, AO 53-244726]

B.6. Not federally enforceable. Sulfur Dioxide - Sulfur Content. The sulfur content of the No. 2 fuel oil shall not exceed 0.5 percent, by weight.
[AO 53-244726]

Excess Emissions

B. 7. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

B. 8. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

B.9. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor or the permittee upon each fuel delivery. See specific condition **B.12.**
[Rule 62-213.440, F.A.C.]

B.10. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

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

B.11. The test method for visible emissions shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.
[Rules 62-204.800, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

B.12. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91, or the respective successor ASTM method(s).
[Rules 62-213.440 and 62-297.440, F.A.C.; and, AO 53-244726]

B.13. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

B.14. Applicable Test Procedures.

(a) Required Sampling Time.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

[Rule 62-297.310(4)(a)2.c., F.A.C.]

B.15. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

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

a. Did not operate; or

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

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

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

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

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

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.
(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.; SIP approved; and, AO 53-244726]

B.16. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
[Rule 62-297.310(7)(a)4., F.A.C.]

Recordkeeping and Reporting Requirements

B.17. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C.
A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

B.18. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.
[Rule 62-297.310(8), F.A.C.]

Section III. Emissions Unit(s) and Conditions.

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

E.U. ID No.	**Brief Description**
-004	Gas Turbine Peaking Unit 1

Gas Turbine Peaking Unit 1 consists of a gas turbine which drives a generator producing electrical power at a nominal nameplate rating of 20 megawatts. The gas turbine is fired with natural gas, or No. 2 fuel oil with a maximum sulfur content of 0.5 percent by weight. The maximum fuel firing rate is 320 million cubic feet per hour of natural gas (approximately 330 million Btu per hour) or 2,310 gallons per hour of No. 2 fuel oil (approximately 320 million Btu per hour). Gas Turbine Peaking Unit 1 began commercial service in 1973.

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

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

Essential Potential to Emit (PTE) Parameters

C.1. Permitted Capacity.
a. The maximum heat input rate of the turbine is 330 million Btu per hour (lower heating value) at 30 degrees F while firing natural gas and 320 million Btu per hour (lower heating value) at 30 degrees F while firing No. 2 fuel oil.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]
b. **Not Federally Enforceable** The maximum firing rate of the turbine is 320 million cubic feet per hour when firing natural gas or 2,310 gallons per hour when firing No. 2 fuel oil.
[AO 53-244727]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}

C.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **C.13.**
[Rule 62-297.310(2), F.A.C.]

C.3. Methods of Operation - Fuels. Only natural gas or distillate (No. 2) fuel oil shall be fired in the combustion turbine.
[Rule 62-213.410, F.A.C.]

C.4. Hours of Operation. These emissions unit(s) may operate continuously, i.e., 8,760 hours/year.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; and, AO 53-244727]

Emission Limitations and Standards

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

C.5. Visible Emissions. Visible emissions from each turbine shall not be equal to or greater than 20 percent opacity.
[Rule 62-296.320(4)(b)1., F.A.C.; and, AO 53-244727]

C.6. Not federally enforceable. Sulfur Dioxide - Sulfur Content. The sulfur content of the No. 2 fuel oil shall not exceed 0.5 percent, by weight.
[AO 53-244727]

Excess Emissions

C.7. Excess emissions from these emissions units resulting from startup, shutdown or malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

C.8. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

C.9. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by means of a fuel analysis provided by the vendor or the permittee upon each fuel delivery. See specific condition **C.12.**
[Rule 62-213.440, F.A.C.]

C.10. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

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

C.11. The test method for visible emissions shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.
[Rules 62-204.800, 62-296.320(4)(b)4.a. and 62-297.401, F.A.C.]

C.12. The fuel sulfur content, percent by weight, for liquid fuels shall be evaluated using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91, or the respective successor ASTM method(s).
[Rules 62-213.440 and 62-297.440, F.A.C.; and, AO 53-244727]

C.13. Not federally enforceable. Operating Rate During Testing.
Testing of emissions shall be conducted with the emissions unit operating at permitted capacity, which is defined as 95-100 percent of the manufacturer's rated heat input achievable for the average ambient (or conditioned) air temperature during the test. If it is impracticable to test at capacity, then sources may be tested at less than capacity. In such cases, the entire heat input vs. inlet temperature curve will be adjusted by the increment equal to the difference between the design heat input value and 105 percent of the value reached during the test. Data, curves, and calculations necessary to demonstrate the heat input rate correction at both design and test conditions shall be submitted to the Department with the compliance test report.
[Requested in initial Title V permit application response for additional information dated February 10, 1997];

C.14. Applicable Test Procedures.

(a) Required Sampling Time.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

[Rule 62-297.310(4)(a)2.c., F.A.C.]

C.15. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

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

a. Did not operate; or

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

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

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

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

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

(b) Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.
(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.; SIP approved; and, AO 53-244727]

C.16. Visible Emissions Testing - Annual. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:
a. only gaseous fuels; or
b. gaseous fuels in combination with any amount of liquid fuels for less than 400 hours per year; or
c. only liquid fuels for less than 400 hours per year.
[Rules 62-297.310(7)(a)4. & 8., F.A.C.]

Recordkeeping and Reporting Requirements

C.17. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.]

C.18. Test Reports.

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

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

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

Section III. Emissions Unit(s) and Conditions.

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

E.U. ID No.	Brief Description
-005	McIntosh Unit 2 - Fossil Fuel Fired Steam Generator

McIntosh Unit 2 is a nominal 114.7 megawatt (electric) fossil fuel fired steam generator. The unit is fired on low sulfur No. 6 or No. 2 fuel oil with a maximum heat input of 1,115 million Btu per hour, or natural gas with a maximum heat input of 1,184.5 million Btu per hour. McIntosh Unit 2 began commercial service in June, 1976.

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

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

Essential Potential to Emit (PTE) Parameters

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

Unit No.	MMBtu/hr Heat Input	Fuel Type
2	1,184.5	Natural Gas
	1,115	No. 6 Fuel Oil
	1,115	No. 2 Fuel Oil

When a blend of fuel oil and natural gas is fired, the heat input is prorated based on the percent heat input of each fuel. The Acid Rain CEM will not be a method of compliance for the determination of the heat input rate.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}

D.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **D.23.**
[Rule 62-297.310(2), F.A.C.]

D.3. Methods of Operation. Fuels. The only fuels allowed to be burned are natural gas, propane, No. 6 Fuel Oil, No. 2 Fuel Oil and combinations of natural gas, propane, No. 6 Fuel Oil and/or No. 2 Fuel Oil. [Rule 62-213.410, F.A.C.]

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

Emission Limitations and Standards

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

Particulate Matter

D.5. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which:
(1) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel or fossil fuel and wood residue.
(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.
[40 CFR 60.42(a)(1) & (2)]

Sulfur Dioxide

D.6. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of:
(1) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from liquid fossil fuel.
[40 CFR 60.43(a)(1)]

D.7. Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.
[40 CFR 60.43(c)]

Nitrogen Oxides

D.8. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:
(1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.
(2) 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel.
[40 CFR 60.44(a)(1) & (2)]

D.9. When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NOx} = \frac{w(260)+x(86)+y(130)+z(300)}{w+x+y+z}$$

where:
PS_{NOx} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;
w = is the percentage of total heat input derived from lignite;
x = is the percentage of total heat input derived from gaseous fossil fuel;
y = is the percentage of total heat input derived from liquid fossil fuel; and,
z = is the percentage of total heat input derived from solid fossil fuel (except lignite).
[40 CFR 60.44(b)]

Excess Emissions

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

D.10. Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:
(1) Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.
[40 CFR 60.45(b)(2) and 60.45(g)(1)]

D.11. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

D.12. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

D.13. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

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

D.14. In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of 40 CFR 60 or other methods and procedures as specified in 40 CFR 60.46, except as provided in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in 40 CFR 60.46(d).
[40 CFR 60.46(a)]

D.15. The owner or operator shall determine compliance with the particulate matter, and NO_X standards in 40 CFR 60.42, 60.43, and 60.44 as follows:
(1) The emission rate (E) of particulate matter, or NO_X shall be computed for each run using the following equation:

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

E = emission rate of pollutant, ng/J (1b/million Btu).
C = concentration of pollutant, ng/dscm (1b/dscf).
$\%\ O_2$ = oxygen concentration, percent dry basis.
F_d = factor as determined from Method 19.

(2) Method 5 shall be used to determine the particular matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems.
  (i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train may be set to provide a gas temperature no greater than 160 ± 14 °C (320 ± 25 °F).
  (ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration ($\%O_2$). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all the individual O_2 sample concentrations at each traverse point.
  (iii) If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points.
(3) Method 9 and the procedures in 40 CFR 60.11 shall be used to determine opacity.
(5) Method 7 shall be used to determine the NO_X concentration.
  (i) The sampling site and location shall be the same as for the SO_2 sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.
  (ii) For each NO_X sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration ($\%O_2$). The sample shall be taken simultaneously with, and at the same point as, the NO_X sample.
  (iii) The NO_X emission rate shall be computed for each pair of NO_X and O_2 samples. The NO_X emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.
[40 CFR 60.46(b)(1), (2), (3), & (5)]

D.16. Compliance with the sulfur dioxide emission standard of specific condition D.7. shall be demonstrated using the fuel sampling and analysis procedures of specific condition **D.17.**
[Rule 62-213.440, F.A.C. and Applicant Request dated June 14, 1996]

D.17. The following fuel sampling and analysis program shall be used to demonstrate compliance with the sulfur dioxide standard and as the substitute for the sulfur dioxide continuous monitoring system:

a. Determine and record the as-fired fuel sulfur content, percent by weight, (1) for liquid fuels using either ASTM D2622-92, ASTM D4294-90, or both ASTM D4057-88 and ASTM D129-91, or the respective successor ASTM method(s), to analyze a representative sample of the blended fuel following each fuel delivery, (2) for gaseous fuels using ASTM D1072-90, or the respective successor ASTM method.

b. Record daily the amount of each fuel fired, the density of each fuel, and the percent sulfur content by weight of each fuel.

c. Utilize the information in a. and b., above, to calculate the SO_2 emission rate to ensure compliance at all times.

[Rules 62-213.440, F.A.C.]

D.18. When combinations of fossil fuels are fired, the owner or operator (in order to compute the prorated standard as shown in 40 CFR 60.44(b)) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:

(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

(2) ASTM Methods D 240-76 (liquid fuels), or D 1826-77 (gaseous fuels) (incorporated by reference-see 40 CFR 60.17) shall be used to determine the gross calorific values of the fuels.

(3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

[40 CFR 60.46(c)(1), (2), & (3)]

D.19. The owner or operator may use the following as alternatives to the reference methods and procedures in 40 CFR 60.46 or in other sections as specified:

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

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

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

where:

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

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

$\%\ CO_2$ = carbon dioxide concentration, percent dry basis.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

D.21. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

D.22. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

D.23. Applicable Test Procedures.
(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.

2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:

a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.

b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached as part of this permit.

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

D.24. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

D.25. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
    a Did not operate; or
    b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 - September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
    a. Visible emissions, if there is an applicable standard;
    b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
    c. Each NESHAP pollutant, if there is an applicable emission standard.

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

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

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

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

D.26. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
[Rule 62-297.310(7)(a)4., F.A.C.]

D.27. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
[Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

Continuous Monitoring Requirements

D.28. The owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions.
[40 CFR 60.45(a)]

D.29. Sulfur Dioxide. For a fossil fuel fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis under 40 CFR 60.45(d). **The applicant has elected to utilize fuel sampling and analysis in lieu of a continuous monitoring system for sulfur dioxide.** See specific condition **D.19.**
[40 CFR 60.45(b)(2)]

D.30. For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:
(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent.
[40 CFR 60.45(c)(3)]

Recordkeeping and Reporting Requirements

D.31. Excess emission and monitoring system performance reports shall be submitted to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each excess emission and MSP report shall include the information required in 40 CFR 60.7(c).
[40 CFR 60.45(g)]

D.32. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
Rule 62-210.700(6), F.A.C.]

D.33. Submit to the Department a written report of emissions in excess of emission limiting standards for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rule 62-213.440, F.A.C.]

D.34. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.

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

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

Miscellaneous Requirements.

D.35. The permittee shall comply with the requirements contained in Appendix 40 CFR 60, Subpart A, attached to this permit.
[Rule 62-204.800(7)(d), F.A.C.]

Section III. Emissions Unit(s) and Conditions.

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

E.U. ID No.	Brief Description
-006	McIntosh Unit 3 - Fossil Fuel Fired Steam Generator

McIntosh Unit 3 is a nominal 364 megawatt (electric) dry bottom wall-fired fossil fuel fired steam generator. The unit is fired on coal, residual oil, natural gas and co-fires refuse derived fuel (RDF) and petroleum coke. The maximum heat input rate is 3,640 million Btu per hour. Unit 3 is equipped with an electrostatic precipitator (ESP), a flue gas desulfurization system (FGD), and low-NO_x burners to control emissions. McIntosh Unit 3 began commercial service in September, 1982.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; and NSPS - 40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Rule 212.400(6), F.A.C., Prevention of Significant Deterioration (PSD); Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination }

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

{Permitting note: In addition to the requirements listed below, these emissions units are also subject to the standards and requirements contained in the Acid Rain Part of this permit (see Section IV).}

Essential Potential to Emit (PTE) Parameters

E.1. Capacity. The maximum heat input rate is 3,640 MMBtu per hour. The Acid Rain CEM will not be a method of compliance for the determination of the heat input rate.
[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.]

{Permitting note: The heat input limitations have been placed in each permit to identify the capacity of each unit for the purposes of confirming that emissions testing is conducted within 90 to 100 percent of the unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate emission limits and to aid in determining future rule applicability.}

E.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **E.21.**
[Rule 62-297.310(2), F.A.C.]

E.3. Methods of Operation - Fuels. The only fuels allowed to be burned are:

Coal only
Low sulfur fuel oil only (≤ 0.5 percent sulfur by weight)
Coal and up to 10 percent refuse (based on heat input)
Low sulfur fuel oil and up to 10 percent refuse (based on heat input)
Coal and up to 20 percent petroleum coke (based on weight)
Coal and up to 20 percent petroleum coke (based on weight) and 10 percent refuse (based on heat input)
High sulfur fuel oil (> 0.5 percent sulfur by weight)
Natural gas or propane only, or in combination with any of the other fuels or fuel combinations listed above

[Rules 62-4.160(2), 62-210.200, and 62-213.440(1), F.A.C.; and, PSD-FL-008(B)]

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

Emission Limitations and Standards

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

Particulate Matter

E.5. Particulate matter emitted to the atmosphere from the boiler shall not exceed:

(1)	Mode of Firing	Pound / MMBtu Heat Input
	Coal	0.044
	Coal/Petroleum Coke	0.044
	Coal/Refuse	0.050
	Coal/Petroleum Coke/Refuse	0.050
	Oil	0.070
	Oil/Refuse	0.075

(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.
[40 CFR 60.42(a)(2); and, PSD-FL-008(B)]

Sulfur Dioxide

E.6. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of:
(1) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.
(2) 520 nanograms per joule heat input (1.2 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in 40 CFR 60.43(e).
[40 CFR 60.43(a)(1) and (2)]

E.7. When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$PS_{SO2} = [y(340) + z(520)]/(y+z)$

where:
PS_{SO2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired,
y is the percentage of total heat input derived from liquid fossil fuel, and
z is the percentage of total heat input derived from solid fossil fuel.
[40 CFR 60.43(b)]

E.8. Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.
[40 CFR 60.43(c)]

E.9. A flue gas desulfurization system will be installed to treat exhaust gases and will operate such that whenever coal or blends of coal and petroleum coke or refuse are burned, sulfur dioxide gases discharged to the atmosphere from the boiler shall not exceed 10 percent of the potential combustion concentration (90 percent reduction), or 35 percent of the potential combustion concentration (65 percent reduction), when emissions are less than 0.75 pound per million Btu heat input. Compliance with the percent reduction requirement shall be determined on a 30-day rolling average. This compliance information shall be retained for a period of five years and made available by the City upon request of the Department. Whenever blends of petroleum coke with other fuels are co-fired, sulfur dioxide emissions shall not exceed 0.718 pound per million Btu heat input based on a 30-day rolling average and shall comply with the reduction requirements given above.
[PSD-FL-008(B) and Rule 62-213.440, F.A.C.]

E.10. The burning of high sulfur oil (greater than 0.5 percent sulfur by weight) or a combination of high sulfur oil and municipal refuse as an emergency fuel without the use of the SO_2 scrubber will be allowed only when the flue gas desulfurization system malfunctions to the extent that the burning of coal would cause emission limitations to be exceeded. Sulfur dioxide emitted to the atmosphere from the boiler shall not exceed 0.8 pound per million Btu heat input under this condition.
[PSD-FL-008(B)]

E.11. During malfunctions of equipment which cause an interruption of the coal feed to the boiler, the burning of high sulfur oil (greater than 0.5 percent sulfur by weight) or a combination of high sulfur oil and municipal refuse will be allowed only if all flue gases are fully scrubbed by the SO_2 scrubber. Sulfur dioxide emitted to the atmosphere from the boiler shall not exceed 0.8 pound per million Btu heat input under this condition.
[PSD-FL-008(B)]

E.12. Continuous burning of natural gas, low sulfur fuel oil (less than or equal to 0.5 percent sulfur by weight), or combinations of these two fuels with or without the use of the SO_2 scrubber will be allowed.
[PSD-FL-008(B)]

Nitrogen Oxides

E.13. On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, no owner or operator subject to the provisions of 40 CFR 60, Subpart D, shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:
(1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.
(2) 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.
(3) 300 nanograms per joule heat input (0.70 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).
[40 CFR 60.44(a)(1), (2), & (3)]

E.14. Except as provided under paragraphs 40 CFR 60.44(c) and (d), when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NOx} = \frac{w(260)+x(86)+y(130)+z(300)}{w+x+y+z}$$

where:
PS_{NOx} = is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;
w = is the percentage of total heat input derived from lignite;
x = is the percentage of total heat input derived from gaseous fossil fuel;
y = is the percentage of total heat input derived from liquid fossil fuel; and,
z = is the percentage of total heat input derived from solid fossil fuel (except lignite).
[40 CFR 60.44(b)]

Excess Emissions

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

E.15. Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:
(1) Opacity. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.
(2) Sulfur dioxide. Excess emissions for affected facilities are defined as:
  (i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under 40 CFR 60.43.
[40 CFR 60.45(g)(1), & (2)]

E.16. Excess emissions resulting from malfunction shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.
[Rule 62-210.700(1), F.A.C.]

E.17. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

E.18. In addition to the requirements of 40 CFR 60.7, each excess emissions report shall include the periods of oil consumption due to flue gas desulfurization system malfunction.
[PSD-FL-008]

Monitoring of Operations

E.19. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

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

E.20. In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of 40 CFR 60 or other methods and procedures as specified in 40 CFR 60.46, except as provided in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in 40 CFR 60.46(d).
[40 CFR 60.46(a)]

E.21. The owner or operator shall determine compliance with the particulate matter, SO_2, and NO_X standards in 40 CFR 60.42, 60.43, and 60.44 as follows:
(1) The emission rate (E) of particulate matter, SO_2, or NO_X shall be computed for each run using the following equation:

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

E = emission rate of pollutant, ng/J (1b/million Btu).
C = concentration of pollutant, ng/dscm (1b/dscf).
$\%\ O_2$ = oxygen concentration, percent dry basis.
F_d = factor as determined from Method 19.

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

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

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

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

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

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

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

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

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

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

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

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

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

E.22. When combinations of fossil fuels or fossil fuel and wood residue are fired, the owner or operator (in order to compute the prorated standard as shown in 40 CFR 60.43(b) and 60.44(b)) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:
(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.
(2) ASTM Methods D 2015-77 (solid fuels), D 240-76 (liquid fuels), or D 1826-77 (gaseous fuels) (incorporated by reference-see 40 CFR 60.17) shall be used to determine the gross calorific values of the fuels. The method used to determine the calorific value of wood residue must be approved by the Administrator.
(3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.
[40 CFR 60.46(c)(1), (2), & (3)]

E.23. The owner or operator may use the following as alternatives to the reference methods and procedures in 40 CFR 60.46 or in other sections as specified:
(1) The emission rate (E) of particulate matter, SO_2 and NO_X may be determined by using the Fc factor, provided that the following procedure is used:

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

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

where:
E = emission rate of pollutant, ng/J (lb/million Btu).
C = concentration of pollutant, ng/dscm (lb/dscf).
% CO_2 = carbon dioxide concentration, percent dry basis.
F_c = factor as determined in appropriate sections of Method 19.

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

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

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

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

(2) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (320 ° F). The procedures of sections 2.1 and 2.3 of Method 5B may be used with Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

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

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

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

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

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

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

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

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

E.24. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.

[Rule 62-297.310(1), F.A.C.]

E.25. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit operation at permitted capacity, which is defined as 90 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rules 62-297.310(2) & (2)(b), F.A.C.]

E.26. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

E.27. Applicable Test Procedures.
(a) Required Sampling Time.

1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
    a. For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation shall be equal to the duration of the batch cycle or operation completion time.
    b. The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.
    c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.
(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached as part of this permit.
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

E.28. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

E.29. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.

2. For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

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

   a Did not operate; or

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

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

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

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

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

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

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

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

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

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

E.30. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:

a. only gaseous fuel(s); or

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

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

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

E.31. Annual and permit renewal compliance testing for particulate matter emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
[Rules 62-297.310(7)(a)3. & 5., F.A.C.; and, ASP Number 97-B-01.]

Continuous Monitoring Requirements

E.32. Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, and either oxygen or carbon dioxide except as provided in 40 CFR 60.45(b).
[40 CFR 60.45(a)]

E.33. Certain of the continuous monitoring system requirements under 40 CFR 60.45(a) do not apply to owners or operators under the following conditions:
(1) For a fossil fuel-fired steam generator that burns only gaseous fossil fuel, continuous monitoring systems for measuring the opacity of emissions and sulfur dioxide emissions are not required.
(2) For a fossil fuel-fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis under 40 CFR 60.45(d).
(3) Notwithstanding 40 CFR 60.13(b), installation of a continuous monitoring system for nitrogen oxides may be delayed until after the initial performance tests under 40 CFR 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70 percent of the applicable standards in 40 CFR 60.44, a continuous monitoring system for measuring nitrogen oxides emissions is not required. If the initial performance test results show that nitrogen oxide emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a continuous monitoring system for nitrogen oxides within one year after the date of the initial performance tests under 40 CFR 60.8 and comply with all other applicable monitoring requirements under 40 CFR 60.
(4) If an owner or operator does not install any continuous monitoring systems for sulfur oxides and nitrogen oxides, as provided under 40 CFR 60.45(b)(1) and (b)(3) or (b)(2) and (b)(3), a continuous monitoring system for measuring either oxygen or carbon dioxide is not required.
[40 CFR 60.45(b)(1), (2), (3), & (4)]

E.34. For performance evaluations under 40 CFR 60.13(c) and calibration checks under 40 CFR 60.13(d), the following procedures shall be used:
(1) Methods 6, 7, and 3B, as applicable, shall be used for the performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B are given in 40 CFR 60.46(d).
(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of Appendix B to 40 CFR 60.
(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide
Gas................................	{1}
Liquid..............................	1,000
Solid...............................	1,500
Combinations.........................	1,000y+1,500z

{1}Not applicable.

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

(4) All span values computed under 40 CFR 60.45(c)(3) for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.
(5) For a fossil fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all continuous monitoring systems shall be subject to the Administrator's approval.
[40 CFR 60.45(c)(1), (2), (3), (4), & (5)]

E.35. For any continuous monitoring system installed under 40 CFR 60.45(a), the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):
(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

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

where:

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

(2) When a continuous monitoring system for measuring carbon dioxide is selected, the measurement of the pollutant concentration and carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$E = CF_c\,[100/\text{percent } CO_2]$

where:

E, C, F_c and % CO_2 are determined under 40 CFR 60.45(f).
[40 CFR 60.45(e)(1) and (2)]

E.36. The values used in the equations under 40 CFR 60.45(e) (1) and (2) are derived as follows:
(1) E = pollutant emissions, ng/J (lb/million Btu).
(2) C = pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^4 M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where M = pollutant molecular weight, g/g-mole (lb/lb-mole). M = 64.07 for sulfur dioxide and 46.01 for nitrogen oxides.
(3) % O_2, % CO_2 = oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under 40 CFR 60.45(a).
(4) F, F_c = a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388-77 (incorporated by reference-see 40 CFR 60.17), F = $2,723 \times 10^{-17}$ dscm/J (10,140 dscf/million Btu and $F_c = 0.532 \times 10^{-17}$ scm CO_2 /J (1,980 scf CO_2 /million Btu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388-77 (incorporated by reference-see 40 CFR 60.17), F = 2.637×10^{-7} dscm/J (9,820 dscf/million Btu) and $F_c = 0.486 \times 10^{-7}$ scm CO_2 /J (1,810 scf CO_2 /million Btu).
(iii) For liquid fossil fuels including crude, residual, and distillate oils, F = 2.476×10^{-7} dscm/J (9,220 dscf/million Btu) and $F_c = 0.384 \times 10^{-7}$ scm CO_2 /J (1,430 scf CO_2 /million Btu).
(iv) For gaseous fossil fuels, F = 2.347×10^{-7} dscm/J (8,740 dscf/million Btu). For natural gas, propane, and butane fuels, $F_c = 0.279 \times 10^{-7}$ scm CO_2 /J (1,040 scf CO_2 /million Btu) for natural gas, 0.322×10^{-7} scm CO_2 /J (1,200 scf CO_2/million Btu) for propane, and 0.338×10^{-7} scm CO_2 /J (1,260 scf CO_2 /million Btu) for butane.

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

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

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

(SI units)

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

(English units)

$$F_c = \frac{20.0(\%C)}{GCV}$$

(SI units)

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

(English units)

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

(ii) GCV is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015-77 for solid fuels and D1826-77 for gaseous fuels as applicable.
(These two methods are incorporated by reference-see 40 CFR 60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or F_c value shall be subject to the Administrator's approval.

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

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

where:

X_i = the fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.)

F_i or $(F_c)_i$ = the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.

n = the number of fuels being burned in combination.

[40 CFR 60.45(f)(1), (2), (3), (4), (5), & (6)]

E.37. Continuous monitors shall be installed and operated in accordance with 40 CFR 60.45 and 60.13. In addition, an ASTM-certified automatic solid fossil fuel sampler shall be installed which produces a representative daily sample for analysis of sulfur, moisture, heating value and ash. The solid fossil fuel data shall be used in conjunction with emissions factors and the continuous monitoring data to calculate SO_2 reduction.
[PSD-FL-008(B)]

Recordkeeping and Reporting Requirements

E.38. Excess emission and monitoring system performance reports shall be submitted to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each excess emission and MSP report shall include the information required in 40 CFR 60.7(c). The summary report form shall contain the information and be in the format shown in figure 1 (attached to this permit) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.
[40 CFR 60.7(d) & 60.45(g)]

E.39. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
Rule 62-210.700(6), F.A.C.]

E.40. Submit to the Department a written report of emissions in excess of emission limiting for each calendar quarter. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations. All recorded data shall be maintained on file by the Source for a period of five years.
[Rule 62-213.440, F.A.C.]

E.41. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.
(b) The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

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

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

Miscellaneous Requirements.

E.42. The permittee shall comply with the requirements contained in Appendix 40 CFR 60, Subpart A, attached to this permit.
[Rule 62-204.800(7)(d), F.A.C.]

E.43. The City shall maintain and submit to the Department on an annual basis for a period of five years from the date that the unit is initially co-fired with petroleum coke, information demonstration in accordance with 40 CFR 52.21(b)(33) and 40 CFR 52.21(b)(21)(v) that the operational changes did not result in emissions increases of carbon monoxide, nitrogen oxides, or sulfuric acid mist.
[PSD-FL-008(B)]

Section III. Emissions Unit(s) and Conditions.

Subsection F. This section addresses the following emissions unit.

E.U. ID No.	**Brief Description**
-028	McIntosh Unit 5 – 250 MW Simple Cycle Stationary Combustion Turbine

McIntosh Unit 5 is a Westinghouse 501G combustion turbine operating in a simple cycle, once through steam generator. The turbine is fired with natural gas or a maximum 0.05 percent, by weight, sulfur content No. 2 or superior grade of distillate fuel oil. Emissions are initially controlled using Dry Low NO_X combustion when firing natural gas; water injection when firing distillate fuel oil; use of inherently clean fuels; and, good combustion practices. Ultimately the combustors will be replaced and nitrogen oxides emissions will be reduced by the use of either Ultra Low NO_X burners or the addition of a selective catalytic reduction (SCR) system. 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.

{Permitting note(s): The emissions unit is regulated under Acid Rain, Phase II; NSPS - 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Rule 62-212.400(5), F.A.C., Prevention of Significant Deterioration (PSD); Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination, dated July 10, 1998. The simple cycle combustion turbine began operation in March, 2000.}

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

Essential Potential to Emit (PTE) Parameters

F.1. Permitted 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 2,407 million Btu per hour when firing natural gas, nor 2,236 million Btu per hour 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 approved by the Department, attached in appendix W501G McIntosh #5, Lakeland FL – Maximum Heat Input as a Function of Compressor Inlet Temperature (1/5/01), for the heat input correction to other temperatures may be utilized to establish heat input rates over a range of temperatures for compliance determination. Monitoring required under condition **F.24.** shall satisfy periodic monitoring requirements for heat input.
[Rules 62-4.160(2), 62-210.200(PTE) and 62-213.440(1)(b)1.b., F.A.C.; and, PSD-FL-245C]

F.2. Emissions Unit Operating Rate Limitation After Testing. See specific condition **F.40.**
[Rule 62-297.310(2), F.A.C.]

F.3. Methods of Operation. Fuels. Only pipeline natural gas or a maximum 0.05 percent, by weight, sulfur content No. 2 or superior grade of distillate fuel oil shall be fired in this unit.
[Rules 62-212.400, 62-212.410, and 62-213.410, F.A.C.; and, PSD-FL-245]

F.4. Hours of Operation. This emissions unit may operate continuously, i.e., 8,760 hours/year.
[Rule 62-210.200(PTE), F.A.C.; and, PSD-FL-245]

F.5. Fuel Usage as Heat Input.

(a) Natural Gas. Fuel usage as heat input shall not exceed 15.639 x 10^{12} Btu (LHV) per year (rolled monthly) until the unit achieves the NO_X emission limits (other than the initial limits) given in specific conditions **F.12.** through **F.15.** Thereafter, only the hourly heat input limits given in specific condition **F.1.** apply.

(b) Fuel Oil. Fuel usage as heat input shall not exceed 599 x 10^9 Btu (LHV) per year (rolled monthly).
[PSD-FL-245]

Control Technology

F.6. Westinghouse Dry Low NO_X (DLN) combustors shall be installed on the stationary combustion turbine to control nitrogen oxides emissions while firing natural gas.
[PSD-FL-245]

F.7. The 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 conditions **F.11.** through **F.15.** 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 conditions **F.11.** through **F.15.** are not achievable by ULN combustors by this date.
[PSD-FL-245]

F.8. 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 conditions **F.11.** through **F.15.** or the carbon monoxide (CO) limits given in specific conditions **F.16.** and **F.17.** are not met.
[PSD-FL-245]

F.9. 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.
[PSD-FL-245]

F.10. The permittee shall provide manufacturer's emissions performance verses 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 and ULN systems in the diffusion firing mode shall be minimized when firing natural gas.
[PSD-FL-245]

Emission Limitations and Standards

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

F.11. The following table is a summary of the BACT determination and is followed by the applicable specific conditions **F.12.** through **F.20.** Values for NO_X are corrected to 15% O_2. Values for CO are corrected to 15% O_2 only until May 1, 2002.

Operational Mode	NO_X (ppm)	CO (ppm)	VOC (ppm)	PM/Visibility (% Opacity)	Technology and Comments
Simple Cycle	25 - NG (basis) 262 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.

[PSD-FL-245C]

F.12. Nitrogen Oxides. Until May 1, 2002, the concentration of NO_X in the exhaust gas shall not exceed 262 pounds per hour (at ISO conditions) on a 24-hour 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-hour 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 262 pounds per hour (when firing natural gas) and shall exceed neither 42 ppm @ 15% O_2 nor 431 pounds per hour (when firing fuel oil) to be demonstrated by stack tests.
[PSD-FL-245C]

F.13. Nitrogen Oxides. No later than May 1, 2002, the concentration of NO_X in the exhaust gas shall not exceed 85 pounds per hour (at ISO conditions) on a 24-hour 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-hour 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 pounds per hour (when firing natural gas) and shall not exceed 42 ppm @ 15% O_2 or 431 pounds per hour (when firing fuel oil) to be demonstrated by stack tests.
[PSD-FL-245C]

F.14. Nitrogen Oxides. 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-hour average, as measured by the CEMS. In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 85 pounds per hour (when firing natural gas) and 148 pounds per hour (when firing fuel oil) to be demonstrated by stack tests.
[PSD-FL-245]

F.15. Nitrogen Oxides. If conventional SCR is installed in conjunction with the 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 a 3-hour average, as measured by the CEMS. In addition, NO_X emissions calculated as NO_2 (at ISO conditions) shall not exceed 71.1 pounds per hour (when firing natural gas) and 148 pounds per hour (when firing fuel oil) to be demonstrated by stack tests.
[PSD-FL-245]

F.16. Carbon Monoxide. 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 and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 161 pounds per hour (when firing natural gas) and 568 pounds per hour (when firing fuel oil).
[PSD-FL-245C]

F.17. Carbon Monoxide. After May 1, 2002, the concentration of CO in the exhaust gas when firing natural gas shall not exceed 25 ppmvd and 90 ppmvd when firing fuel oil as measured by EPA Method 10. CO emissions (at ISO conditions) shall not exceed 106 pounds per hour (when firing natural gas) and 386 pounds per hour (when firing fuel oil).
[PSD-FL-245]

F.18. Sulfur Dioxide. SO_2 emissions (at ISO conditions) shall not exceed 8 pounds per hour when firing pipeline natural gas and 127 pounds per hour when firing maximum 0.05 percent, by weight, sulfur content No. 2 or superior grade distillate fuel oil, as measured by applicable compliance methods (see specific conditions **F.36.**). Emissions of SO_2 shall not exceed 38.4 tons per year.
[PSD-FL-245C and Applicant Request to Escape PSD Review]

F.19. Visible Emissions. Visible emissions shall not exceed 10 percent opacity.
[PSD-FL-245]

F.20. Volatile Organic Compounds. The concentration of VOC in the exhaust gas when firing natural gas shall not exceed 4 ppmvd and 10 ppmvd when firing fuel oil as measured by EPA Method(s) 18 and/or 25A. VOC emissions (at ISO conditions) shall exceed 11 pounds per hour (when firing natural gas) and 25 pounds per hour (when firing fuel oil).
[PSD-FL-245C]

Excess Emissions

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

F.21. Excess emissions from this emissions unit resulting from startup, shutdown, malfunction or fuel switching shall be permitted provided that best operational practices to minimize emissions 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 the Department for longer duration
[Rule 62-210.700(1), F.A.C.; and, PSD-FL-245]

F.22. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

F.23. At all times, including periods of startup, shutdown and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
[40 CFR 60.11(d)]

F.24. The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG and using water injection to control NO_X emissions shall operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in the turbine. This system shall be accurate to within ±5.0 percent and shall be approved by the Administrator.
[40 CFR 60.334(a)]

F.25. The owner or operator of any stationary gas turbine subject to the provisions of 40 CFR 60, Subpart GG shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:
(1) If the turbine is supplied its fuel from a bulk storage tank, the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source.
(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with 40 CFR 60.334(b).
[40 CFR 60.334(b)(1) & (2)]

F.26. 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 the nitrogen content of the fuel shall be provided by the vendor. The analysis shall also specify the methods by which the analysis was conducted and shall comply with the requirements of 40 CFR 60.335(d). See specific condition **F.36.**
[PSD-FL-245]

F.27. 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 **F.36.** for the measurement of sulfur in gaseous fuels, or an approved alternate 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 custom 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 one grain per 100 cubic feet 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 analyses 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 **F.36.** are used.

[PSD-FL-245]

F.28. Determination of Process Variables.

(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

[Rule 62-297.310(5), F.A.C.]

Test Methods and Procedures

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

F.29. To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Department to determine the nitrogen content of the fuel being fired.
[40 CFR 60.335(a)]

F.30. During performance tests to determine compliance, measured NO_X emissions at 15 percent oxygen will be adjusted to ISO ambient atmospheric conditions by the following correction factor:

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

where:
NO_X = Emissions of NO_X at 15 percent oxygen and ISO standard ambient conditions.
NO_X obs = Measured NO_X emission at 15 percent oxygen, ppmv.
P_{ref} = Reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure.
P_{obs} = Measured combustor inlet absolute pressure at test ambient pressure.
e = Transcendental constant (2.718)
H_{obs} = Specific humidity of ambient air at test.
T_{amb} = Temperature of ambient air at test.
[40 CFR 60.335(c)(1)]

F.31. When determining compliance with 40 CFR 60.332, Subpart GG - Standards of Performance for Stationary Gas Turbines, the monitoring device of 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with the permitted NO_X standard at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.
[40 CFR 60.335(c)(2)]

F.32. The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 as follows:
c. U.S. EPA Method 20 (40 CFR 60, Appendix A) shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NO_X emissions shall be determined at each of the load conditions specified in 40 CFR 60.335(c)(2).
[40 CFR 60.335(c)(3)]

F.33. 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 after initial operation of the unit for that fuel, and annually thereafter as indicated in this permit, by using the reference methods as described in the latest edition of 40 CFR 60, Appendix A, and adopted by reference in Chapter 62-204.800, F.A.C. Emission limit compliance dates shall conform to the timetable specified in specific condition **F.11.**
[PSD-FL-245]

F.34. Compliance Testing. 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 shakedown period not to exceed 100 days after restarting the combustion turbine) 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, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40 CFR 60, Subpart GG and (I,A) short-term NO_X BACT limits (Method 7E or RATA test data may be used to demonstrate compliance for the annual test requirement).
- EPA Reference Method(s) 18 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

[PSD-FL-245]

F.35. Continuous compliance with the NO_X emission limits: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on 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 specific condition **F.59.** 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.
[PSD-FL-245]

F.36. 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/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 latest version) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or latest version) 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).
[PSD-FL-245]

F.37. 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).
[PSD-FL-245]

F.38. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the BACT VOC emission limit. Thereafter, the CO emission limit will be employed as a surrogate and no annual testing is required.
[PSD-FL-245]

F.39. To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in 40 CFR 60.335(a) and (d) to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency. See specific conditions **F.25.** through **F.27.**
[40 CFR 60.335(e)]

F.40. Operating Rate During Testing. Testing of emissions shall be conducted with the emissions unit 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 verses ambient temperature). If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than permitted capacity. In this case, subsequent emissions unit operation is limited by adjusting the entire heat input verses 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 emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rule 62-297.310(2), F.A.C.; and, PSD-FL-245]

F.41. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

F.42. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

F.43. Applicable Test Procedures.
(a) Required Sampling Time.
1. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
2. Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
c. The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.
(b) Minimum Sample Volume. Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.
(c) Required Flow Rate Range. For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

(d) Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, attached to this permit.
(e) Allowed Modification to EPA Method 5. When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.
[Rule 62-297.310(4), F.A.C.]

F.44. The permittee shall comply with the requirements contained in APPENDIX SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

F.45. Frequency of Compliance Tests. The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.
(a) General Compliance Testing.

3. The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to Rule 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:
   a Did not operate; or
   b. In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours.

4. During each federal fiscal year (October 1 -- September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:
   a. Visible emissions, if there is an applicable standard;
   b. Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and
   c. Each NESHAP pollutant, if there is an applicable emission standard.

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

8. Any combustion turbine that does not operate for more than 400 hours per year shall term of its air operation permit.

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

(b) Special Compliance Tests. When the Department's Southwest District office, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it may require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.
(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.
[Rule 62-297.310(7), F.A.C.; and, SIP approved]

Continuous Monitoring Requirements

F.46. 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 conditions **F.11.** through **F.15.**, 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 conditions **F.11.** through **F.15.**
[PSD-FL-245 and 40 CFR 60.7]

F.47. 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) specified in specific condition **F.55.** Subject to EPA approval, calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) and specified in specific condition **F.31.** will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emissions 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.
[PSD-FL-245]

F.48. 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.
[PSD-FL-245]

F.49. A performance evaluation of the CEMS shall be conducted during any required performance test or within 30 days thereafter in accordance with the applicable performance specifications of 40 CFR 60, Appendix B and at other times as required by the Administrator.
[40 CFR 60.13(c)]

F.50. The zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts shall be checked at least once daily in accordance with a written procedure. The zero and span shall, at a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications of 40 CFR 60, Appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified.
[40 CFR 60.13(d)(1)]

F.51. Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d)(1), all continuous monitoring systems shall be in continuous operation and shall meet the minimum frequency of operation as follows:
(2) All continuous monitoring systems for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.
[40 CFR 60.13(e)]

F.52. All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters form the affected facility are obtained.
[40 CFR 60.13(f)]

F.53. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous monitoring system breakdown, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non-reduced form (e.g. ppm pollutant and percent O_2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit. (e.g. rounded to the nearest 1 percent opacity).
[40 CFR 60.13(h)]

F.54. Continuous Monitoring System. 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 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40 CFR 75.
[PSD-FL-245]

Record Keeping and Reporting Requirements

F.55. For the purpose of reports required under 40 CFR 60.7(c), periods of excess emissions that shall be reported are defined as follows:

a. Nitrogen oxides. Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with the permitted nitrogen oxide standard by the initial performance test required in 40 CFR 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the initial performance test. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

[Rule 62-296.800, F.A.C.; and, 40 CFR 60.334(c)(1)]

F.56. The owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form [see 40 CFR 60.7(d)] to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or, the CMS data are to be used directly for compliance determination, in which case quarterly reports shall be submitted; or, the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information:

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

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

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

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

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

[40 CFR 60.7(c)(1), (2), (3), & (4); and, PSD-FL-245]

F.57. The summary report form shall contain the information and be in the format shown in Figure 1 (attached) unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.

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

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

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

F.58. (1) Notwithstanding the frequency of reporting requirements specified in 40 CFR 60.7(c), an owner or operator who is required by an applicable subpart to submit excess emissions and monitoring systems performance reports (and summary reports) on a quarterly (or more frequent) basis may reduce the frequency of reporting for that standard to semiannual if the following conditions are met:

- (i) For 1 full year (e.g., 4 quarterly or 12 monthly reporting periods) the affected facility's excess emissions and monitoring systems reports submitted to comply with a standard under this part continually demonstrate that the facility is in compliance with the applicable standard;
- (ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in 40 CFR 60, Subpart A, and the applicable standard; and
- (iii) The Administrator does not object to a reduced frequency of reporting for the affected facility, as provided in 40 CFR 60.7(e)(2).

(2) The frequency of reporting of excess emissions and monitoring systems performance (and summary) reports may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the required recordkeeping period prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation and maintenance requirements. Such information may be used by the Administrator to make a judgment about the source's potential for noncompliance in the future. If the Administrator disapproves the owner or operator's request to reduce the frequency of reporting, the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(3) As soon as monitoring data indicate that the affected facility is not in compliance with any emission limitation or operating parameter specified in the applicable standard, the frequency of reporting shall revert to the frequency specified in the applicable standard, and the owner or operator shall submit an excess emissions and monitoring systems performance report (and summary report, if required) at the next appropriate reporting period following the noncomplying event. After demonstrating compliance with the applicable standard for another full year, the owner or operator may again request approval from the Administrator to reduce the frequency of reporting for that standard as provided for in 40 CFR 60.7(e)(1) and (e)(2).
[40 CFR 60.7(e)(1)]

F.59. Malfunction Reporting. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Department's Southwest District office within one (1) working day of: the nature, extent, and duration of the excess emissions; and, the actions taken to correct the problem. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department.
[Rule 62-210.700(6), F.A.C.; and, PSD-FL-245]

F.60. All recorded data shall be maintained on file by the Source for a period of five years.
[Rule 62-213.440, F.A.C.]

F.61. Test Reports.
(a) The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department's Southwest District office on the results of each such test.
(b) The required test report shall be filed with the Department's Southwest District office as soon as practical but no later than 45 days after the last sampling run of each test is completed.
(c) The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department's Southwest District office to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

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

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

Miscellaneous Requirements.

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

F.63. Circumvention. No owner or operator subject to the provisions of 40 CFR 60 shall build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere.
[40 CFR 60.12]

F.64. 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.
[PSD-FL-245]

Section IV. This section is the Acid Rain Part.

Operated by: Lakeland Electric
ORIS code: 676

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

The emissions unit(s) listed below are regulated under Acid Rain, Phase II.

E.U. ID No.	Brief Description
-001	Boiler - McIntosh Unit 1
-005	Boiler - McIntosh Unit 2
-006	Boiler - McIntosh Unit 3
-028	McIntosh Unit 5 – 250 MW Simple Cycle Stationary Combustion Turbine

A.1. The Phase II permit application(s) submitted for this facility, as approved by the Department, are a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application(s) listed below:

a. DEP Form No. 62-210.900(1)(a), dated 07/01/95.

[Chapter 62-213, F.A.C. and Rule 62-214.320, F.A.C.]

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

E.U. ID No.	EPA ID	Year	2000	2001	2002	2003
-001	No. 01	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	907*	907*	907*	907*
-005	No. 02	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	1029*	1029*	1029*	1029*
-006	No. 03	SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	9928*	9928*	9928*	9928*
-028		SO2 allowances, under Table 2 or 3 of 40 CFR Part 73	0*	0*	0*	0*

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

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

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

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

Subsection B. This subsection addresses Acid Rain, Phase I.

{Permitting note: The U.S. EPA issues Acid Rain Phase I permit(s)}

The emissions unit listed below is regulated under Acid Rain Part, Phase I, for Lakeland Electric, C. D. McIntosh, Jr. Power Plant, **Facility ID No.:** 1050004, **ORIS code:** 676

E.U. ID No.	**Brief Description**
-006	Boiler - McIntosh Unit 3

B.1. The owners and operators of these Phase I acid rain unit(s) must comply with the standard requirements and special provisions set forth in the permit(s) listed below:

a. Phase I permit dated 03/27/97.

[Chapter 62-213, F.A.C.]

B.2. Nitrogen oxide (NO_X) requirements for the following Acid Rain unit is as follows:

E.U. ID No.	**EPA ID**	**NOx limit***
-006	**No. 03**	Pursuant to 40 CFR 76.8(d)(2), the Florida Department of Environmental Protection approves a NO_X early election compliance plan for unit No. 03. The compliance plan is effective for calendar year 2000 through calendar year 2007. Under the compliance plan, this unit's annual average NO_X emission rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under "40 CFR 76.5(a)(2) of 0.50 lb/mmBtu" for dry bottom wall-fired boilers. If the unit is in compliance with its applicable emission limitation for each year of the plan, then the unit shall not be subject to the applicable emission limitation, under "40 CFR 76.7(a)(2) of 0.46 lb/mmBtu" for dry bottom wall-fired boilers until calendar year 2008. In addition to the described NO_X compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NO_X compliance plan and the requirements covering excess emissions.

* Based on the Phase II NO_X Compliance Plan dated December 4, 1997.

B.3. Comments, notes, and justifications: none

ATTACHMENT MC-FI-C13

RISK MANAGEMENT PLAN VERIFICATION

EPA United States Environmental Protection Agency

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460
OFFICE OF SOLID WASTE AND EMERGENCY RESPONSE

December 27, 2001

**Ed Colter
City of Lakeland
3400 East Lake Parker Drive
Lakeland, FL 33805-0513**

**EPA Facility ID#: 1000 0009 4738
Postmark Date: 12/20/2001
Anniversary Date: 12/20/2006**

NOTIFICATION LETTER: COMPLETE RMP

The U.S. Environmental Protection Agency (EPA) received your Risk Management Plan (RMP) dated with the above postmark date. **This letter notifies you that your RMP is "complete" according to EPA's completion check.** The completion check is a program implemented by EPA to determine whether a submitted RMP includes the minimum amount of information every RMP must provide. The completion check does not assess whether a submitted RMP should have provided additional information or whether the information it provides is accurate or appropriate. In other words, it does not indicate that the RMP meets the requirements of 40 CFR Part 68.

Please note the anniversary date indicated above. Your RMP must be revised and updated by this date or earlier as required by 40 CFR §68.190. Please also note your EPA Facility ID number as identified at the top of this letter; all future Risk Management Plan supmissions, corrections and other correspondence must include this number.

Your RMP (excluding the Offsite Consequence Analysis data) can be viewed on RMP*Info™, a national database on the Internet at http://www.epa.gov/enviro.

If you have any questions, please call one of the following numbers:

(1) For RMP rule interpretation questions, call the EPCRA Hotline at (800) 424-9346 or (703) 412-9810 (in the D.C. Metro area).

(2) For RMP*Submit installation and software questions, or information on the status of your RMP, contact the RMP Reporting Center at (703) 816-4434, or write to the:

RMP Reporting Center
P.O. Box 3346
Merrifield, VA 22116-3346

(3) For more information on the Risk Management Program, you can contact your Implementing Agency. Your Implementing Agency is **Florida Department of Community Affairs, 2555 Shumard Oak Boulevard, Tallahassee, FL, 32399, Phone: 850-413-9970.**

Thank you for your cooperation in this matter.

Sincerely,

RMP Reporting Center

Enclosure:
Risk Management Plan (if submitted on paper)

ATTACHMENT MC-FI-C14

COMPLIANCE REPORT AND PLAN

ATTACHMENT MC-FI-C14

COMPLIANCE REPORT AND PLAN

On the date specified in Attachment MC-FI-C15, the facility and emission units identified in this application are in compliance with the Applicable Regulations identified in this application form. Compliance with the conditions set forth in this operation permit will be certified on an annual basis by the submittal of the Statement of Compliance – Title V Source DEP Form No. 62-213.900(7). This report will be submitted by March 1 of each year for the prior calendar year. Compliance with the allowable emission limiting standards for oil firing shall be determined within 720 unit operating hours on oil as indicated by the EPA Region IV letter from R. Douglas Nealy dated February 14, 2001. Compliance with the installation of the oxidation catalyst as required by Condition 17 of PSD-FL-245 will be demonstrated by a properly signed and sealed certification.

ATTACHMENT MC-FI-C15

COMPLIANCE CERTIFICATION

ATTACHMENT MC-FI-C15

COMPLIANCE CERTIFICATION

The facility and emission units identified in this application are in compliance with the Applicable Regulations identified in the application form and attachments referenced in this section. The compliance report for this facility will be submitted by March 1st of each year for the prior calendar year. The compliance statement is as follows:

> I, he undersigned, am the Responsible Official as defined in Chapter 62-210.200, F.A.C., of the Title V source for which this report is being submitted. I hereby certify, based on reasonable information and belief formed after reasonable inquiry, that the statements made and data contained in this report are true, accurate, and complete.

Timothy C Bates
Signature, Responsible Official

4/28/03
Date

Timothy C. Bates, Director of Energy Supply

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 1 – Fossil-Fuel-Fired Steam Generator (FFFSG)

4. Emissions Unit Identification Number: [ ] No ID
ID: **001** [ ] ID Unknown

5. Emissions Unit Status Code: **A**	6. Initial Startup Date: **February 1971**	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [X]

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

This emission unit is a gas and oil-fired steam-generating unit. This unit is also permitted to burn "on-specification" used oil generated by the City of Lakeland.

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:	90	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: **985** 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 based on higher heating value (HHV) of natural gas. Heat input for No. 6 fuel oil is 950 mmBtu/hr. Heat input for "on-specification" used oil is 950 mmBtu/hr. Heat input based on fuel flow and sampling.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment MC-FI-C12	

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? **S001**

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: **150** feet

7. Exit Diameter: **9** feet

8. Exit Temperature: **277** °F

9. Actual Volumetric Flow Rate: **310,000** acfm

10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm

12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **409.2** North (km): **3106.2**

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

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

Segment Description and Rate: Segment 1 of 3

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Residual (No. 6) oil**		
2. Source Classification Code (SCC): **1-01-004-01**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **6.33**	5. Maximum Annual Rate: **55,451**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2.5**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**
10. Segment Comment (limit to 200 characters): **Maximum hourly rate based on maximum heat input for oil firing.**		

Segment Description and Rate: Segment 2 of 3

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Natural Gas**		
2. Source Classification Code (SCC): **1-01-006-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **0.97**	5. Maximum Annual Rate: **8,497**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,024**
10. Segment Comment (limit to 200 characters): **Propane is used for ignition only (SCC 1-01-010-02)**		

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

Segment Description and Rate: Segment 3 of 3

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

On-specification used oil as defined in 40 CFR 279.11 and generated by the City of Lakeland.

2. Source Classification Code (SCC): **1-01-013-02**	3. SCC Units: **1,000 Gallons Burned**

4. Maximum Hourly Rate: **6.3**	5. Maximum Annual Rate: **42**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **2.5**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**

10. Segment Comment (limit to 200 characters):

Compliance with "on-specification" requirements contained in Condition A.11, Section III of Title V permit.

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
PM			EL
PM_{10}			NS
NO_X			NS
CO			NS
SO_2			EL
VOC			NS

Emissions Unit Information Section 1 **of** 8 **Unit 1**

Pollutant Detail Information Page 1 **of** 2 **Particulate Matter - Total**

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: **119** lb/hour **520** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.125 lb/mmBtu** Reference: **Permit 1050004-011-AV**	7. Emissions Method Code: **0**

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

Air Operation Permit 105004-011-AV: 0.1 lb/mmBtu steady state and 0.3 lb/mmBtu soot blowing (3 hours in 24 hours)

0.125 lb/mmBtu x 950 mmBtu/hr = 118.75 lb/hr
118.75 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 520 TPY

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

Based on oil firing.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.1 lb/mmBtu**	4. Equivalent Allowable Emissions: **95.0** lb/hour **416** tons/year

5. Method of Compliance (limit to 60 characters):

Annual stack test; EPA Method 5, 5B, 5F or 17; if greater than 400 hr/yr oil.

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

Oil firing (No. 6 oil, "on-specification"): heat input = 950 mmBtu/hr; steady state.

Emissions Unit Information Section 1 of 8 Unit 1

Pollutant Detail Information Page 1 of 2 Particulate Matter - Total

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

Potential/Fugitive Emissions

1. Pollutant Emitted:	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: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.3 lb/mmBtu**	4. Equivalent Allowable Emissions: **285** lb/hour **156** tons/year

5. Method of Compliance (limit to 60 characters):

Annual stack test; EPA Method 5, 5B, 5F, or 17.

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

Soot blowing and load change: 0.3 lb/mmBtu during 3 hours in any 24-hour period of excess emissions allowed for boiler cleaning (soot blowing) and load change.

Emissions Unit Information Section 1 of 8 Unit 1

Pollutant Detail Information Page 2 of 2 Sulfur Dioxide

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: **2,613** lb/hour **11,443** tons/year

4. Synthetically Limited? ☐

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

6. Emission Factor: **2.75 lb/mmBtu**
   Reference: **Permit 1050004-011-AV**

7. Emissions Method Code: **0**

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

   2.75 lb/mmBtu x 950 mmBtu/hr = 2,612.5 lb/hr
   2,612.5 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 11,442.8 ton/yr

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

   Based on maximum heat input of 950 mmBtu/hr oil firing.

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **RULE**

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units: **2.75 lb/mmBtu**

4. Equivalent Allowable Emissions: **2,613** lb/hour **11,443** tons/year

5. Method of Compliance (limit to 60 characters):
   Fuel analysis ASTM methods D-4294-83 and D-240 or the respective successor ASTM Method(s).

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

   2.75 lb/mmBtu based on 2.5 percent S in fuel oil.

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 3

1. Visible Emissions Subtype: **VE20**	2. Basis for Allowable Opacity: [**X**] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: **20** % Exceptional Conditions: **40** %
Maximum Period of Excess Opacity Allowed: **2** min/hour

4. Method of Compliance:

Annual compliance test; EPA Method 9

5. Visible Emissions Comment (limit to 200 characters):

For exception conditions 27 percent opacity for 6 minutes allowed as an alternative to 40 percent standard under FDEP Rule 62-296.405(1)(a).

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

Continuous Monitoring System: Continuous Monitor 1 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **SO_2**

3. CMS Requirement: [**X**] Rule [ ] Other

4. Monitor Information:
Manufacturer: **Advanced Pollution Inst.**
Model Number: **152** Serial Number: **169**

5. Installation Date: **29 Dec 1994**	6. Performance Specification Test Date:

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

CEM required pursuant to 40 CFR Part 75.

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 3

1. Visible Emissions Subtype: **VE60**	2. Basis for Allowable Opacity: [X] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: **60** % Exceptional Conditions: **100** %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:

Annual compliance test; EPA Method 9 (if greater than 400 hours)

5. Visible Emissions Comment (limit to 200 characters):

FDEP Rule 62-210.700(3). 100 percent for four 6-minute periods in 3 hours; 60 percent for 3 hours per 24 hours allowed for soot blowing/load changing.

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

Continuous Monitoring System: Continuous Monitor 2 of 5

1. Parameter Code: **EM**	2. Pollutant(s): **NO_X**

3. CMS Requirement: [X] Rule [ ] Other

4. Monitor Information:
Manufacturer: **Advanced Pollution Inst.**
Model Number: **252** Serial Number: **135**

5. Installation Date: **29 Dec 1994**	6. Performance Specification Test Date:

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

CEM required pursuant to 40 CFR Part 75.

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

Visible Emissions Limitation: Visible Emissions Limitation 3 of 3

1. Visible Emissions Subtype: VE99	2. Basis for Allowable Opacity: [X] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: 100 % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: 60 min/hour

4. Method of Compliance:

None

5. Visible Emissions Comment (limit to 200 characters):

FDEP Rule 62-210.700(1) and (2); (1) malfunction for 2 hours (120 minutes) per 24-hour period for malfunction; (2) startup/shutdown requires best operation practices.

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

Continuous Monitoring System: Continuous Monitor 3 of 5

1. Parameter Code: VE	2. Pollutant(s):

3. CMS Requirement: [X] Rule [ ] Other

4. Monitor Information:
Manufacturer: United Science Inc.
Model Number: 500C Serial Number: 0993686

5. Installation Date: 29 Dec 1994	6. Performance Specification Test Date:

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

CEM required pursuant to 40 CFR Part 75.

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

1. Visible Emissions Subtype:

2. Basis for Allowable Opacity: [ ] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:

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 4 of 5

1. Parameter Code: **CO_2**

2. Pollutant(s):

3. CMS Requirement: [X] Rule [ ] Other

4. Monitor Information:
Manufacturer: **Milton Roy**
Model Number: **3300** Serial Number: **N4A1172T**

5. Installation Date:
29 Dec 1994

6. Performance Specification Test Date:

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

CEM required pursuant to 40 CFR Part 75.

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

Visible Emissions Limitation: Visible Emissions Limitation _____ of _____

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

1. Parameter Code: **FLOW**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **Air Monitor** Model Number: **CEM**	Serial Number: **6231D**
5. Installation Date: **29 Dec 1994**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **Flow monitor required pursuant to 40 CFR Part 75.**	

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

Supplemental Requirements

1. Process Flow Diagram
[X] Attached, Document ID: MC-EU1-J1 [ ] Not Applicable [ ] Waiver Requested

2. Fuel Analysis or Specification
[X] Attached, Document ID: MC-EU1-J2 [ ] Not Applicable [ ] Waiver Requested

3. Detailed Description of Control Equipment
[ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested

4. Description of Stack Sampling Facilities
[X] Attached, Document ID: MC-EU1-J4 [ ] Not Applicable [ ] Waiver Requested

5. Compliance Test Report

[X] Attached, Document ID: MC-EU1-J5

[ ] Previously submitted, Date: ____________

[ ] Not Applicable

6. Procedures for Startup and Shutdown
[X] Attached, Document ID: MC-EU1-J6[ ] 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: MC-EU1-J11 [ ] 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: MC-FI-C12 [ ] Not Applicable

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

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

[X] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
Attached, Document ID: MC-EU1-J15

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

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

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

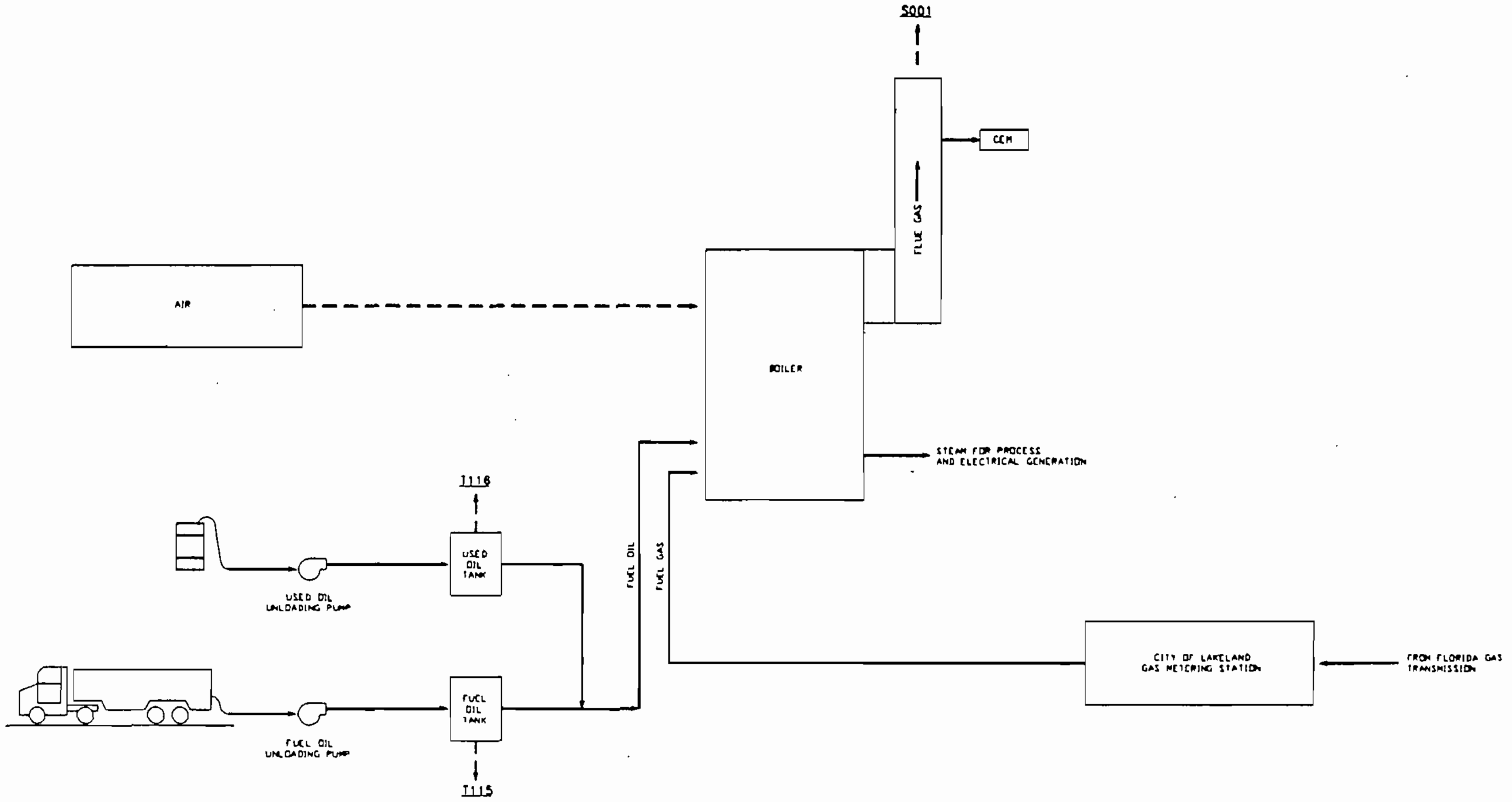
[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
Attached, Document ID:________

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

[ ] Not Applicable

ATTACHMENT MC-EU1-J1

PROCESS FLOW DIAGRAM



REV. NO.	BY	DATE	APPR.	REVISION
3	MG	5-28-96	HP	ISSUED FOR TITLE V
2	MG	5-15-96	HP	CHANGE TITLE
1	MG	8-9-95		ADDED USED OIL TANK AND PUMP

LAKELAND
ELECTRIC
& WATER

DESCRIPTION

LAKELAND ELECTRIC & WATER UTILITIES
C.D. McINTOSH POWER PLANT
UNIT NO. 1
PROCESS FLOW DIAGRAM

DIVISION PRODUCTION ENGINEERING
ENGINEER PATTERSON
DRN. BY: MGIEGER
DATE 9-19-94
APPR. BY:

CAD
SCALE NONE
PROJ. NO. AIR PERMIT
DWG. NO. LMC-EU1-L1/SKM-25
REV. 3

SIZE B

ATTACHMENT MC-EU1-J2

FUEL ANALYSIS OR SPECIFICATION

COMMERCIAL TESTING & ENGINEERING CO.

GENERAL OFFICES: 1919 SOUTH HIGHLAND AVE., SUITE 210-B, LOMBARD, ILLINOIS 60148 • TEL: 630-953-9300 FAX: 630-953-9306

SINCE 1908

SGS Member of the SGS Group (Société Générale de Surveillance)

Committed To Excellence

ADDRESS ALL CORRESPONDENCE TO:
16130 VAN DRUNEN RD.
SOUTH HOLLAND, IL 60473
TEL: (708) 331-2900
FAX: (708) 333-3060
www.comteco.com

July 8, 2002

CITY OF LAKELAND
3030 E. Lake Parker Dr.
Lakeland, FL 33805
Attn: Steven Parrish

Sample identification by
City of Lakeland

Kind of sample
reported to us #6 Diesel Fuel

Sample ID: 350-02 Unit-1

Sample taken at ------

Sample taken by City of Lakeland

Date sampled June 6, 2002

Date received June 27, 2002

P.O. No. MR-17247

Analysis Report No. 71-182853 Page 1 of 1

	As Received
GRAVITY	
Specific at 60/60°F	0.9936
Lb/gallon at 60°F	8.275
°API	10.9
HEATING VALUE	
Btu/lb	18,142
Btu/gal at 60°F	150,125
Sulfur, % Wt.	2.40
Ash, % Wt.	0.056

METHODS
Gravity: ASTM D 4052; Heating Value: ASTM D 240; Sulfur: ASTM D 4294; Ash: ASTM D 482

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

South Holland Laboratory

MEMBER ACIL

OVER 40 BRANCH LABORATORIES STRATEGICALLY LOCATED IN PRINCIPAL COAL MINING AREAS, TIDEWATER AND GREAT LAKES PORTS, AND RIVER LOADING FACILITIES

F-590 [illegible]

TERMS AND CONDITIONS ON REVERSE

ATTACHMENT MC-EU1-J2

FUEL ANALYSIS
NATURAL GAS

Parameter	Typical Value	Max Value
Relative density	0.58 (compared to air)	
heat content	950 - 1124 Btu/cu ft. (HHV)	
% sulfur	0.43 grains/CCF [1]	1 grain/100
CF		
% nitrogen	0.8% by volume	
% ash	negligible	

Note: The values listed are "typical" values based upon information supplied by Florida Gas Transmission (FGT). However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

---

[1] Data from laboratory analysis

ATTACHMENT MC-EU1-J2

FUEL ANALYSIS
NO. 6 FUEL OIL

Parameter	Typical Value	Max Value
API gravity @ 60 F	8[1]	-
Relative density	8.2 lb/gal [2]	
Heat content	18,300 Btu / lb (HHV)	
% sulfur	2.5 [2]	2.5 [3]
% nitrogen	0.25 - 0.50	
% ash	negligible	0.01 [1]

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit.

ATTACHMENT MC-EU1-J2

FUEL ANALYSIS
NO. 2 FUEL OIL

Parameter	Typical Value	Max Value
API gravity @ 60 F	30[1]	-
Relative density	6.92 lb/gal [2]	
Heat content	18,400 Btu / lb (LHV)	
% sulfur	<0.5 [2]	0.5 [3]
% nitrogen	0.025 - 0.030	
% ash	negligible	0.01 [1]

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

---

[1] Data taken from the fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit.

ATTACHMENT MC-EU1-J2

FUEL ANALYSIS
ON-SPEC USED OIL

Parameter	Typical Value	Max Value
API gravity @ 60 F	28[1]	-
Relative density	7.4lb/gal [2]	
Heat content	18,700 Btu / lb (HHV)	
% sulfur	0.3 - 0.5 [2]	2.5 [3]
% nitrogen	0.3	
% ash	0.4 - 0.9	

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the FPC fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit.

ATTACHMENT MC-EU1-J2

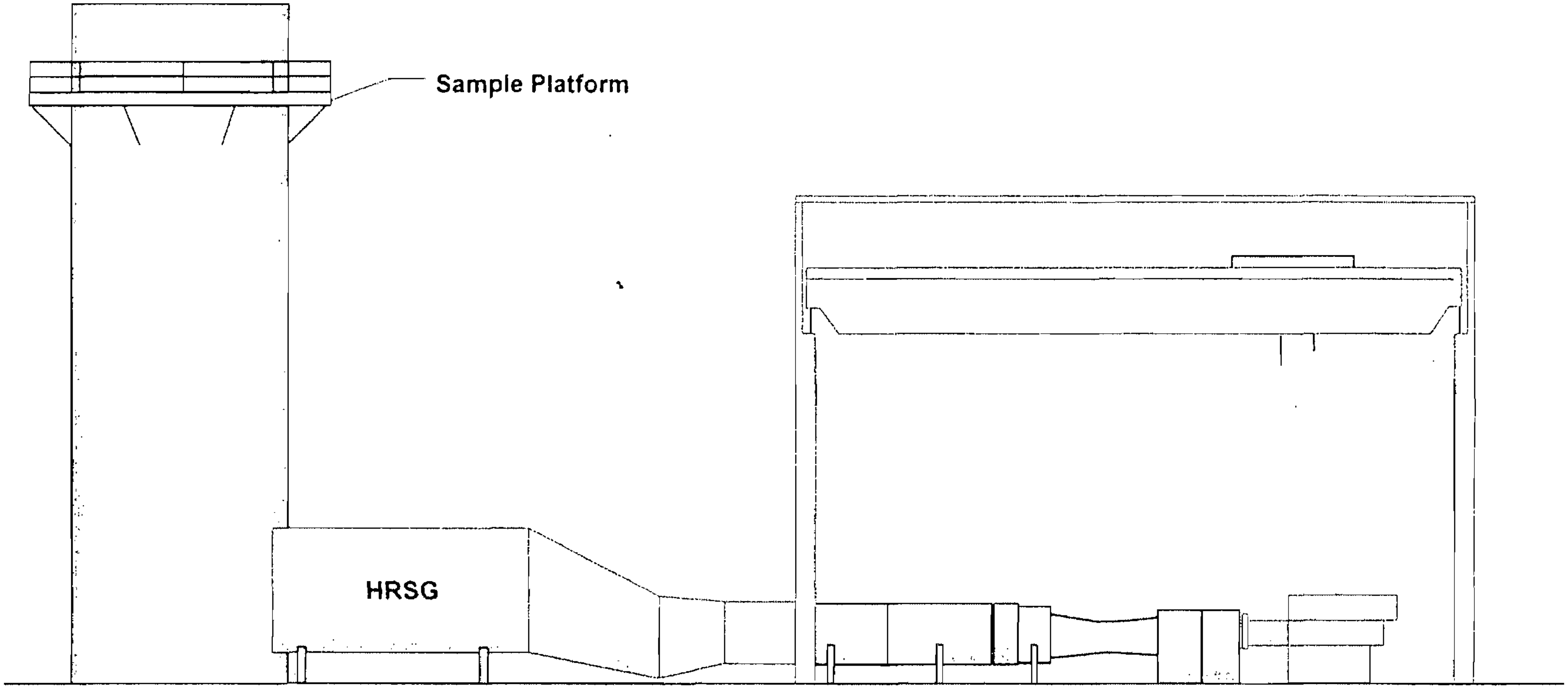
FUEL ANALYSIS
PROPANE ANALYSIS

Parameter	Typical Value
heat content	90,500 Btu/gal
% sulfur	negligible
% nitrogen	0.8% by volume
% ash	negligible

ATTACHMENT MC-EU1-J4

DESCRIPTION OF STACK SAMPLING FACILITIES

CATALYST AIR MANAGEMENT, INC.



GENERAL ARRANGEMENT

TITLE CITY OF LAKELAND - C.D. McINTOSH POWER PLANT		
DESCRIPTION GENERAL ARRANGEMENT - UNIT 5		DATE 3/02/02
SCALE None	DRAWN BY MT TAYLOR	REVISED

ATTACHMENT MC-EU1-J5

COMPLIANCE TEST REPORT

RECEIVED
JUL 18 2002
Environmental Affairs

M064

CATALYST
AIR MANAGEMENT, INC.

AIR QUALITY TESTING SERVICES

CITY OF LAKELAND
C.D. McINTOSH POWER PLANT
UNIT 1

PARTICULATE EMISSIONS TEST REPORT

Catalyst Air Management, Inc.
Report Number 138-051

July 15, 2002

COPY

2505 Byington-Solway Road
Knoxville, Tennessee 37931
(865) 531-0075 • Fax (865) 531-0750

1531 Wyngate Drive
DeLand, Florida 32724
(904) 943-9241 • Fax (904) 943-9212

6 Unionville Roa
Douglassville, Pennsylvania 1951
(610) 326-7888 • Fax (610) 326-332

TABLE OF CONTENTS

PROJECT FACT SHEET

NAME OF SOURCE OWNER: City of Lakeland

SOURCE IDENTIFICATION: C.D. McIntosh Unit 1
FDEP Permit No. 1050004-009-AV
EU ID No. 001

LOCATION OF SOURCE: 3030 East Lake Parker Drive
Lakeland, FL

TYPE OF OPERATION: Fossil Fuel Fired Steam Generating Unit

TYPES OF TESTS PERFORMED: Sample Traverse-EPA Method 1
Volumetric Flow-EPA Method 2
O_2/CO_2-EPA Method 3A
Moisture-EPA Method 4
Particulate-EPA Method 17

SOURCE ANALYZERS: API NOx -252 - 135
API SO_2.- 152 - 169
California Instruments CO_2-3300-N4A1172T
Air Monitor Corp. - Masstron - 6231D

TEST COMPANY: Catalyst Air Management, Inc.
2505 Byington Solway Road
Knoxville, TN 37931

SITE SUPERVISOR: Mike Taylor - Principal

TEST PERSONNEL: Steve Webb - Project Manager
Kevin Garbett - Technician

REPORT PREPARATION: Mike Taylor - Principal

TEST DATES: June 6, 2002

OWNER's REPRESENTATIVE: John Guiseppi

TEST OBSERVER: William Scheroder - FDEP

1.0 Introduction

Catalyst Air Management, Inc. (Catalyst) was contracted by the City of Lakeland to perform the annual particulate compliance testing for Unit 1 at C.D. McIntosh Power Plant.

The sampling program was conducted June 6, 2002. The testing was performed by Messers. Mike Taylor, Steve Webb and Kevin Garbett of Catalyst, with the assistance of personnel assigned by the City of Lakeland. Mr. John Guiseppi of the City of Lakeland coordinated plant operation during the testing.

2.0 Summary of Test Results

A summary of test results developed by this source sampling program is presented in Tables 1 through 4. The summary tables are presented as follows:

TABLE 1

Summary of Particulate Emissions

C.D McIntosh Unit 1

Source	Emission Rate (lb/mmBtu)	Permit (lb/mmBtu)
Unit 1 Steady State	0.093	0.10
Unit 1 Soot Blow	0.120	0.30

TABLE 2

Summary of Visible Emissions

C.D. McIntosh Unit 1

Source	Average VE (%)	Highest 6 min (%)	Permitted (%)
Unit 1 Steady State	3.0	6.7	20
Unit 1 Soot Blow	0.4	3.8	60

3.0 Results of Testing

The individual test run results are shown in Tables 3 and 4, and are tabulated in Appendix 1. The results indicate that Unit 1 is in compliance with the emission limits of Permit No.1050004-009-AV.

TABLE 3
ISOKINETTIC SUMMARY
Steady State

Client: **City of Lakeland**
Plant: **McIntosh Unit 1**
Location: **Stack**

Run Number:		**1 SS**	**2 SS**	**3 SS**
Date:		6/6/02	6/6/02	6/6/02
Run Time:	Start	10:17	12:09	15:08
	End	11:20	13:11	16:10
Unit Load (MW):		91	91	91
Unit Load (MMBTU/HR)):		869.0	864.3	851.2
DN - Nozzle Diameter:		0.185	0.189	0.188
Pbar - Barometric Pressure:		29.83	29.83	29.83
TT - Sampling Time:		60	60	60
VM - Meter Volume:		40.005	40.67	41.567
TM - Avg. Meter Temp (F):		88	87	92
PM - Avg. Delta H (in. of H2O):		1.295	1.369	1.395
Y - Meter Calibration Factor:		1.00	1.00	1.00
VMSTD - Std. Gas Volume (SCF):		38.508	39.250	39.777
Vlc - Volume Water Collected:		112	110	102
%M - Percent Moisture:		12.0	11.7	10.8
Bws - Mole Fraction, Dry:		0.120	0.117	0.108
%CO2 - Carbon Dioxide, Dry:		11.8	11.8	11.8
%O2 - Oxygen, Dry:		6.0	6.0	5.9
%EA - Excess Air		38.2	38.2	37.3
MD - Dry Molecular Weight:		30.13	30.13	30.12
MS - Wet Molecular Weight:		28.67	28.71	28.82
A - Stack Area, SQ.FT:		63.62	63.62	63.62
PS - Static Press. (in. of H2O):		29.88	29.88	29.88
TS - Stack Temp. (F):		268	270	267
CP - Pitot Coefficient:		0.84	0.84	0.84
VS - Stack Gas Velocity (AFPS):		90.3	92.9	93.8
QS - Stack Gas Volume (DSCFM):		219,624	226,091	231,631
QA - Stack Gas Volume (ACFM):		344,665	354,423	358,080
%I - Isokinetic Ratio:		99.7	94.5	94.5
Mg - Catch weight:		126.6	131.0	127.8
Gr/DSCF - Emission Concentration:		0.051	0.051	0.049
LB/MMBtu - Emission Concentration:		0.093	0.095	0.091

Average Gr/DSCF	0.051
Average LB/Mmbtu	**0.093**

TABLE 4
ISOKINETTIC SUMMARY
Soot Blow

Client: **City of Lakeland**
Plant: **McIntosh Unit 1**
Location: **Stack**

Run Number:	**1 SB**	**2 SB**	**3 SB**
Date:	6/6/02	6/6/02	6/6/02
Run Time: Start	7:30	8:55	13:38
End	8:38	10:00	14:41
Unit Load (MW):	88	91	92
Unit Load (MMBTU/HR)):	832.5	861.9	883.1
DN - Nozzle Diameter:	0.189	0.188	0.188
Rbar - Barometric Pressure:	29.83	29.83	29.83
TT - Sampling Time:	60	60	60
VM - Meter Volume:	39.878	41.122	41.152
TM - Avg. Meter Temp (F):	77	83	90
PM - Avg. Delta H (in. of H2O):	1.353	1.461	1.393
Y - Meter Calibration Factor:	1.00	1.00	1.00
VMSTD - Std. Gas Volume (SCF):	39.191	39.975	39.511
Vlc - Volume Water Collected:	88	114	123
%M - Percent Moisture:	9.6	11.8	12.8
Bws - Mole Fraction, Dry:	0.096	0.118	0.128
%CO2 - Carbon Dioxide, Dry:	11.7	11.7	11.9
%O2 - Oxygen, Dry:	6.1	6.1	5.8
%EA - Excess Air	39.1	39.1	36.4
MD - Dry Molecular Weight:	30.12	30.12	30.14
MS - Wet Molecular Weight:	28.96	28.68	28.58
A - Stack Area, SQ.FT:	63.62	63.62	63.62
PS - Static Press. (in. of H2O):	29.87	29.88	29.90
TS - Stack Temp. (F):	264	265	274
CP - Pitot Coefficient:	0.84	0.84	0.84
VS - Stack Gas Velocity (AFPS):	87.3	91.3	92.9
QS - Stack Gas Volume (DSCFM):	219,404	223,629	222,142
QA - Stack Gas Volume (ACFM):	333,151	348,662	354,466
%I - Isokinetic Ratio:	97.3	98.4	97.9
Mg - Catch weight:	133.5	156.3	212.6
Gr/DSCF - Emission Concentration:	0.052	0.060	0.083
LB/MMBtu - Emission Concentration:	0.097	0.112	0.151

Average Gr/DSCF 0.065
Average LB/Mmbtu **0.120**

ATTACHMENT MC-EU1-J6

PROCEDURES FOR STARUP AND SHUTDOWN

ATTACHMENT MC-EU1-J6

PROCEDURES FOR STARTUP AND SHUTDOWN MINIMIZING EXCESS EMISSIONS

Startup of the fossil-fuel boilers begins when fuel (propane, natural gas, spec used oil or No. 2 fuel oil) is introduced into one or more burners within the boiler and lighted (commencement of combustion). Startup is complete and steady-state operation begins when the combustion process has stabilized and the megawatt load on the unit is stable and above 10-15 percent load.

Shutdown of the fossil-fuel boilers begins when unit megawatt load is decreased to below 10-15 percent of maximum and continues until the final burner gun is removed from service.

Emissions may be detected during all modes of boiler operation by various continuous emissions monitors. Continuous monitors are currently in place for NO_x, CO_2, SO_2, flow and opacity. Audible and visual alarms are activated whenever the permitted value for opacity is approached.

Countermeasures which may be taken in the event of excess emissions include, but are not limited to:

- Burner elevation loading
- Proper excess air adjustments
- Recognizing and removal of faulty burners
- Fuel oil temperature adjustments
- Proper and timely operation of boiler cleaning devices
- Removal of the unit from system-dispatch mode (load control)
- Reduction of unit megawatt load
- Stopping and restarting of boiler cleaning devices
- Lowering load ramp rate
- Pressure rate changes
- Placing boiler controls on manual
- Adjusting burner dampers to increase windbox/furnace air pressure

Knowledge of the appropriate countermeasures to take when excess emissions occur is a part of the routine operator training for those who operate the boilers. Topics include current permit limits, maximum

allowable duration of excess emissions, appropriate countermeasures for excess emissions, duty to notify, and fuels and combustion training.

ATTACHMENT MC-EU1-J11

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT MC-EU1-J11

ALTERNATIVE METHODS OF OPERATION FOSSIL FUEL STEAM GENERATOR

The fossil fuel steam generator can operate on both natural gas and fuel oil (No. 6 through No. 2 fuel oil). The maximum sulfur content in the fuel oil shall not exceed 2.5 percent. The No. 2 fuel oil is used as pilot fuel during startup, shutdown, and malfunctions. On-spec oil is co-fired with other fuels. This unit can operate for the entire year at varying loads (i.e., 8,760 hours 0 to 100% load) and can fire fuels, alone or in combination, with no restrictions on hours of operation.

ATTACHMENT MC-EU1-J15

ACID RAIN PART APPLICATION

Phase II Acid Rain Part Application

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

This submission is: ☐ New ☐ Revised ☒ Renewal

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

Plant Name C. D. McIntosh, Jr. State FL ORIS Code 676

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

	Compliance Plan			
a	b	c	d	e
Unit ID#	Unit will hold allowances in accordance with 40 CFR 72.9(c)(1)	Repowering Plan	New Units Commence Operation Date	New Units Monitor Certification Deadline
1	Yes			1/1/96
2	Yes			1/1/96
3	Yes			1/1/96
5	Yes		1/1/99	3/1/99
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			
	Yes			

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

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

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

Plant Name (from Step 1)

Standard Requirements

Acid Rain Part Requirements.

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

Monitoring Requirements.

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

Sulfur Dioxide Requirements.

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

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

Excess Emissions Requirements.

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

Recordkeeping and Reporting Requirements.

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

Plant Name (from Step 1)

Recordkeeping and Reporting Requirements (cont)

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

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

Liability.

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

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

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

Certification

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

Name	Timothy C Bates	
Signature	Timothy C Bates	Date 4/29/03

Acid Rain Program

Instructions for

Phase II Acid Rain Part Application

(40 CFR 72.30 - 72.31 and Rule 62-214.320, F.A.C.)

The Acid Rain Program regulations require the designated representative to submit an Acid Rain part application for Phase II for each source with an Acid Rain unit. A complete Phase II part application is binding on the owners and operators of the Acid Rain source and is enforceable in the absence of an Acid Rain part until the permitting authority either issues an Acid Rain part to the source or disapproves the application.

Please type or print. The alternate designated representative may sign in lieu of the designated representative. If assistance is needed, contact the title V permitting authority.

STEP 1 Use the plant name and ORIS Code listed on the Certificate of Representation for the plant. An ORIS code is a 4 digit number assigned by the Energy Information Agency (EIA) at the U.S. Department of Energy to power plants owned by utilities. If the plant is not owned by a utility but has a 5 digit facility code (also assigned by EIA), use the facility code. If no code has been assigned or if there is uncertainty regarding what the code number is, contact EIA at (202) 426-1234 (for ORIS codes), or (202) 426-1269 (for facility codes).

STEP 2 For column "a," identify each Acid Rain unit at the Acid Rain source by providing the appropriate unit identification numbers, consistent with the unit identification numbers entered on the Certificate of Representation, with unit identification numbers listed in NADB (for units that commenced operation prior to 1993), and with unit identification numbers used in reporting to DOE and/or EIA. For new units without identification numbers, owners and operators may assign such numbers consistent with EIA and DOE requirements. NADB is the National Allowance Data Base for the Acid Rain Program, and can be downloaded from the Acid Rain Program Website at "www.epa.gov/acidrain/" or obtained on diskette by calling the Acid Rain Hotline. This data file is in dBase format for use on an IBM-compatible PC and requires 2 megabytes of hard drive memory.

For column "c," enter "yes" only if a repowering technology petition has been approved for the unit by U.S. EPA, an initial repowering extension plan was approved by the title V permitting authority and activated by the designated representative, and a repowering extension plan renewing the original repowering extension plan has been included with the current acid rain part application for that unit.

For columns "d" and "e," enter the commence operation date(s) and monitor certification deadline(s) for new units in accordance with 40 CFR 75.4. If the commence operation date or monitor certification date changes after the Phase II part is issued, the designated representative must submit a request for an administrative correction under Rule 62-214.370(6), F.A.C.

Submission Deadlines

For new units, an initial Phase II part application must be submitted to the title V permitting authority at least 24 months before the date the unit commences operation. Phase II acid rain renewal applications must be submitted at least 6 months in advance of the expiration of the acid rain portion of a title V permit, or such longer time as provided for under the title V permitting authority's operating permits regulation.

Submission Instructions

Submit this form and 1 copy to the appropriate title V air permitting authority. If you have questions regarding this form, contact your local, State, or EPA Regional acid rain contact, or call EPA's Acid Rain Hotline at (202) 564-9620.

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 2 – Fossil-Fuel-Fired Steam Generator (FFFSG)

4. Emissions Unit Identification Number: [ ] No ID
ID: **005** [ ] ID Unknown

5. Emissions Unit Status Code: **A**	6. Initial Startup Date: **June 1976**	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [X]

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

This emission unit is fired on low Sulfur No. 6 or No. 2 fuel oil or natural gas.

Emissions Unit Control Equipment

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

   NO_X control incorporated in furnace design through the use of flue gas recirculation (FGR).

2. Control Device or Method Code(s): **26**

Emissions Unit Details

1. Package Unit:
   Manufacturer: Model Number:
2. Generator Nameplate Rating: **115** 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: **1185** 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 based on HHV of natural gas. Heat input for residual oil is 1,115 mmBtu/hr. Heat input based on fuel flow and sampling.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment MC-FI-C12	

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? **S002**

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: **157** feet

7. Exit Diameter: **10.5** feet

8. Exit Temperature: **277** °F

9. Actual Volumetric Flow Rate: **380,200** acfm

10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm

12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **409.2** North (km): **3106.2**

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

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):

Residual (No. 6) oil

2. Source Classification Code (SCC): **1-01-004-01**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **7.43**	5. Maximum Annual Rate: **65,087**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.7**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**

10. Segment Comment (limit to 200 characters):

Maximum hourly rate based on maximum heat input for oil firing. Unit can be co-fired with natural gas. No. 2 fuel oil can be used.

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): **1-01-006-01**	3. SCC Units: **Million Cubic Feet**	
4. Maximum Hourly Rate: **1.157**	5. Maximum Annual Rate: **10,133**	6. Estimated Annual Activity Factor:
9. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,024**

10. Segment Comment (limit to 200 characters):

Maximum hourly rate based on maximum heat input. Propane is used for ignition/startup only (SCC 1-01-010-02)

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	26		EL
CO			NS
VOC			NS
PM_{10}			NS

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

Potential/Fugitive Emissions

1. Pollutant Emitted: **PM**

2. Total Percent Efficiency of Control:

3. Potential Emissions: **118.5** lb/hour **518.8** tons/year

4. Synthetically Limited? [ ]

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

6. Emission Factor: **0.1 lb/mmBtu**
   Reference: **Permit 1050004-011-AV**

7. Emissions Method Code: **0**

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

   0.1 lb/mmBtu x 1,184.5 mmBtu/hr = 118.45 lb/hr
   118.45 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 518.8 TPY

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

   Based on maximum heat input of natural gas = 1,184.5 mmBtu/hr.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units: **0.1 lb/mmBtu**

4. Equivalent Allowable Emissions: **118.5** lb/hour **518.8** tons/year

5. Method of Compliance (limit to 60 characters):

   None

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

   Fired with natural gas.

Emissions Unit Information Section 2 **of** 8 Unit 2

Pollutant Detail Information Page 1 **of** 3 **Particulate Matter - Total**

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

Potential/Fugitive Emissions

1. Pollutant Emitted:

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:
RULE

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.1 lb/mmBtu

4. Equivalent Allowable Emissions:
112 lb/hour **488** tons/year

5. Method of Compliance (limit to 60 characters):
Annual stack test; EPA Method 5 or 17, if greater than 400 hr/yr oil.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):
Fired with No. 6 or No. 2 fuel oil based on maximum heat input of 1,115 mmBtu/hr.

Emissions Unit Information Section 2 of 8 Unit 2

Pollutant Detail Information Page 2 of 3 Sulfur Dioxide

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

<u>Potential/Fugitive Emissions</u>

1. Pollutant Emitted: **SO_2**	2. Total Percent Efficiency of Control:
3. Potential Emissions: **892** lb/hour **3,907** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.8 lb/mmBtu** Reference: **40 CFR Part 60, Subpart D**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **0.8 lb/mmBtu x 1,115 mmBtu/hr = 892 lb/hr** **892 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 3,907 ton/yr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on maximum heat input of oil firing equal to 1,115 mmBtu/hr.**	

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

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.8 lb/mmBtu (3-hour average) Subpart D**	4. Equivalent Allowable Emissions: **892** lb/hour **3,907** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel analysis and total heat input from all fossil fuels burned including gaseous fuels.**	
6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters): **Based on FDEP 62-296.405(2)(c) and 40 CFR Part 60, Subpart D. 40 CFR 60.43(c) allows co-firing.**	

Emissions Unit Information Section 2 of 8 **Unit 2**

Pollutant Detail Information Page 3 of 3 **Nitrogen Oxides**

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: **355** lb/hour **1,556** tons/year
4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year
6. Emission Factor: **0.3 lb/mmBtu**
   Reference: **40 CFR Part 60, Subpart D**
7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters):

   0.3 lb/mmBtu x 1,115 mmBtu/hr = 334.5 lb/hr
   334.5 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 1,556 ton/yr

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

   Based on oil firing.

Allowable Emissions Allowable Emissions 1 of 2

1. Basis for Allowable Emissions Code: **RULE**
2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.3 lb/mmBtu (3-hour average)**
4. Equivalent Allowable Emissions: **355** lb/hour **1,556** tons/year
5. Method of Compliance (limit to 60 characters):

   Annual stack test; EPA Method 7, 7A, 7C, 7D, or 7E

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

   Allowable emissions based on oil firing. If co-firing of oil and gas, the emission limit is prorated based on heat input.

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

Potential/Fugitive Emissions

1. Pollutant Emitted:	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: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.2 lb/mmBtu (3-hour average)**	4. Equivalent Allowable Emissions: **237** lb/hour **1,038** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 7, 7A, 7C, 7D, or 7E**	
6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters): **Allowable emissions based on gas firing pursuant to 62-296.800 F.A.C. and 40 CFR Part 60, Subpart D, Section 6044. If co-firing oil and gas, emission limit is prorated based on heat input.**	

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: 20 % Exceptional Conditions: 27 %
Maximum Period of Excess Opacity Allowed: 6 min/hour

4. Method of Compliance:

Annual VE testing; EPA Method 9

5. Visible Emissions Comment (limit to 200 characters):

FDEP Rule 62-296.800; 40 CFR Part 60, Subpart D, Section 60.42(a).

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

Continuous Monitoring System: Continuous Monitor 1 of 5

1. Parameter Code: EM	2. Pollutant(s): NO_X

3. CMS Requirement: [X] Rule [ ] Other

4. Monitor Information:
Manufacturer: Advanced Pollution Inst.
Model Number: 252 Serial Number: 139

5. Installation Date: 14 Dec 1994	6. Performance Specification Test Date:

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

CEM required pursuant to 40 CFR Part 75.

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**

2. Basis for Allowable Opacity: [X] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: % Exceptional Conditions: **100** %
Maximum Period of Excess Opacity Allowed: **60** min/hour

4. Method of Compliance:
None

5. Visible Emissions Comment (limit to 200 characters):

FDEP Rule 62-210.700(1) and 40 CFR 60, 60.8(c), 60.11(c). Allowed for 2 hours (120 minutes) per 24-hour period for startup, shutdown, and malfunction.

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

Continuous Monitoring System: Continuous Monitor 2 of 5

1. Parameter Code: **EM**

2. Pollutant(s): **SO_2**

3. CMS Requirement: [X] Rule [ ] Other

4. Monitor Information:
Manufacturer: **Advanced Pollution Inst.**
Model Number: **152** Serial Number: **170**

5. Installation Date:
14 Dec 1994

6. Performance Specification Test Date:

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

CEM required pursuant to 40 CFR Part 75.

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

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

1. Parameter Code: **VE**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: **United Science Inc.** Model Number: **500C**	Serial Number: **0993687**
5. Installation Date: **14 Dec 1994**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **CEM required pursuant to 40 CFR Part 75.**	

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:

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 4 of 5

1. Parameter Code: **CO_2**	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other

4. Monitor Information:
Manufacturer: **California Analytical**
Model Number: **3300** Serial Number: **N3H4430T**

5. Installation Date: **14 Dec 1994**	6. Performance Specification Test Date:

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

CEM required pursuant to 40 CFR Part 75.

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:

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 5 of 5

1. Parameter Code: **FLOW**	2. Pollutant(s):

3. CMS Requirement: [X] Rule [ ] Other

4. Monitor Information:
Manufacturer: **Air Monitor**
Model Number: **Musstron** Serial Number: **6232D**

5. Installation Date: **14 Feb 1994**	6. Performance Specification Test Date:

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

Flow monitor required pursuant to 40 CFR Part 75.

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

Supplemental Requirements

1. Process Flow Diagram
[X] Attached, Document ID: MC-EU2-J1 [ ] Not Applicable [ ] Waiver Requested

2. Fuel Analysis or Specification
[X] Attached, Document ID: MC-EU2-J2 [ ] Not Applicable [ ] Waiver Requested

3. Detailed Description of Control Equipment
[ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested

4. Description of Stack Sampling Facilities
[X] Attached, Document ID: MC-EU2-J4 [ ] Not Applicable [ ] Waiver Requested

5. Compliance Test Report
[X] Attached, Document ID: MC-EU2-J5
[ ] Previously submitted, Date: ______
[ ] Not Applicable

6. Procedures for Startup and Shutdown
[X] Attached, Document ID: MC-EU2-J6[ ] 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: MC-EU2-J11 [ ] 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: MC-FI-C12 [ ] Not Applicable

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

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

[X] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
Attached, Document ID: MC-EU1-J15

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

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

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

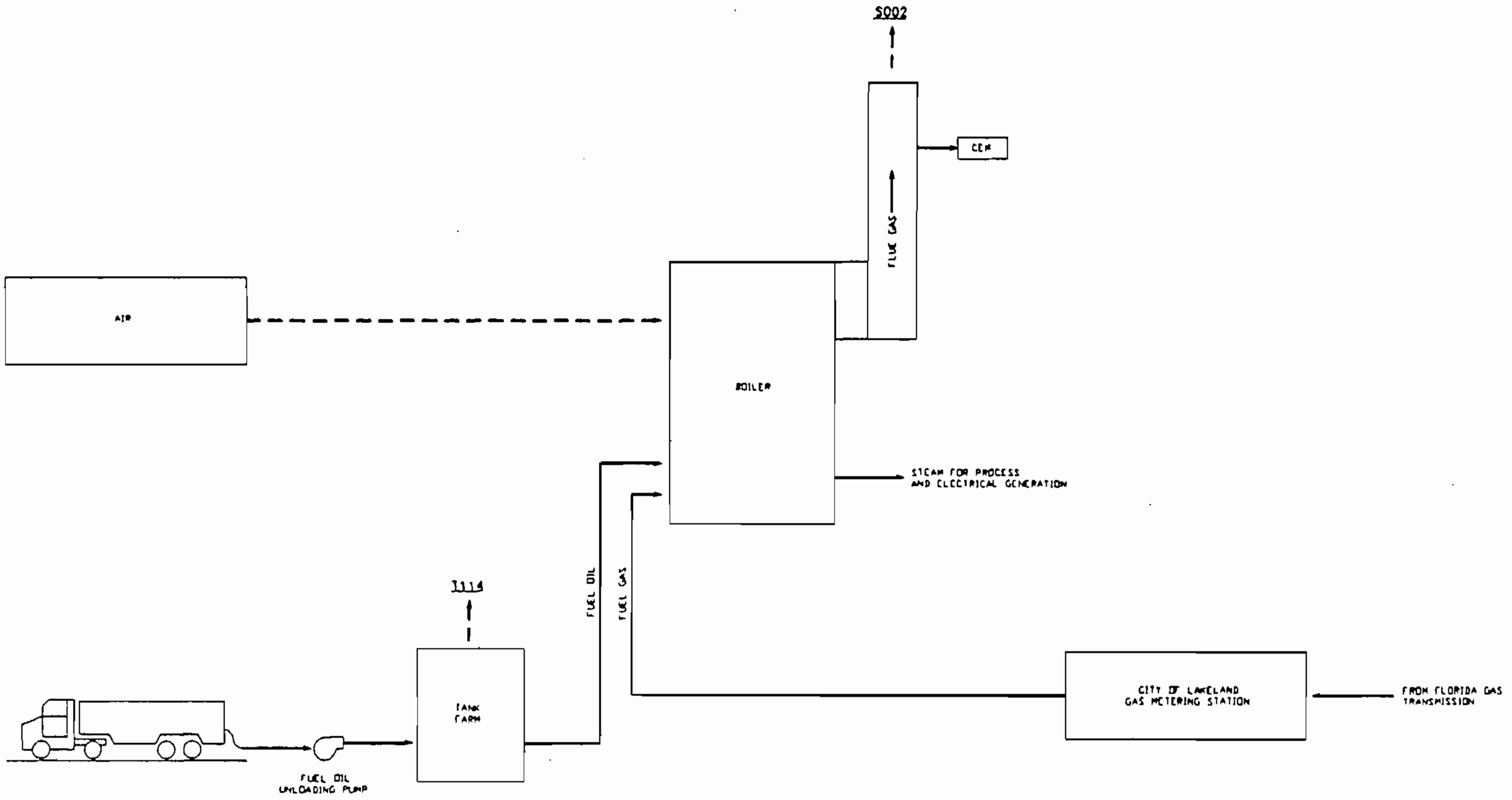
[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
Attached, Document ID:________

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

[ ] Not Applicable

ATTACHMENT MC-EU2-J1

PROCESS FLOW DIAGRAM



REV. NO.	BY	DATE	APPR.	REVISION
2	MG	5-28-96	HP	ISSUED FOR TITLE V
1	MG	5-15-96	HP	CHANGE TITLE

LAKELAND
ELECTRIC
& WATER

DESCRIPTION

LAKELAND ELECTRIC & WATER UTILITIES
C.D. McINTOSH POWER PLANT
UNIT NO. 2
PROCESS FLOW DIAGRAM

DIVISION	PRODUCTION ENGINEERING		
ENGINEER	PATTERSON		
DRN. BY:	MCIEGER	DATE	9-19-94
APPR. BY:			

CAD	SCALE NONE	
PROJ. NO.	AIR PERMIT	
DWG. NO.		REV.
LMC-EU2-L1/SKM-26		2

SIZE B

ATTACHMENT MC-EU2-J2

FUEL ANALYSIS OR SPECIFICATION

COMMERCIAL TESTING & ENGINEERING CO.
GENERAL OFFICES: 1919 SOUTH HIGHLAND AVE., SUITE 210-B, LOMBARD, ILLINOIS 60148 - TEL: 630-953-9300 FAX: 630-953-9306
SINCE 1908
SGS Member of the SGS Group (Société Générale de Surveillance)
Committed To Excellence

ADDRESS ALL CORRESPONDENCE TO.
16130 VAN DRUNEN RD.
SOUTH HOLLAND, IL 60473
TEL: (708) 331-2900
FAX: (708) 333-3060
www.comtesco.com

July 8, 2002

CITY OF LAKELAND
3030 E. Lake Parker Dr.
Lakeland, FL 33805
Attn: Steven Parrish

Sample identification by
City of Lakeland

Kind of sample reported to us: #6 Diesel Fuel

Sample ID: 351-02 UNIT-2

Sample taken at: ------

Sample taken by: City of Lakeland

Date sampled: June 11, 2002

Date received: June 27, 2002

P.O. No. MR-17247

Analysis Report No. 71-182859

Page 1 of 1

	As Received
GRAVITY	
Specific at 60/60°F	0.9524
Lb/gallon at 60°F	7.931
°API	17.1
HEATING VALUE	
Btu/lb	13,546
Btu/gal at 60°F	147,088
Sulfur, % Wt.	0.66
Ash, % Wt.	0.031

METHODS
Gravity: ASTM D 4052; Heating Value: ASTM D 240; Sulfur: ASTM D 4294; Ash: ASTM D 482

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

South Holland Laboratory

MEMBER ACIL

OVER 40 BRANCH LABORATORIES STRATEGICALLY LOCATED IN PRINCIPAL COAL MINING AREAS, TIDEWATER AND GREAT LAKES PORTS, AND RIVER LOADING FACILITIES

TERMS AND CONDITIONS ON REVERSE

ATTACHMENT MC-EU2-J2

FUEL ANALYSIS
NATURAL GAS ANALYSIS

Parameter	Typical Value	Max Value
Relative density	0.58 (compared to air)	
heat content	950 - 1124 Btu/cu ft. (HHV)	
% sulfur	0.43 grains/CCF [1]	1 grain/100 CF
% nitrogen	0.8% by volume	
% ash	negligible	

Note: The values listed are "typical" values based upon information supplied by Florida Gas Transmission (FGT). However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

---

[1] Data from laboratory analysis

ATTACHMENT MC-EU2-J2

FUEL ANALYSIS
NO. 6 FUEL OIL

Parameter	Typical Value	Max Value
API gravity @ 60 F	8[1]	-
Relative density	8.2 lb/gal [2]	
Heat content	18,300 Btu / lb (HHV)	
% sulfur	0.7 [2]	0.728 [3]
% nitrogen	0.25 - 0.50	
% ash	negligible	0.01 [1]

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the fuel procurement specification

[2] Data from laboratory analysis

[3] Data to meet 0.8 lb/10^6 BTU for oil firing only; when co-firing with natural gas, the sufur content can be as high as 2.5 percent.

ATTACHMENTMC-EU2-J2

FUEL ANALYSIS
NO. 2 FUEL OIL

Parameter	Typical Value	Max Value
API gravity @ 60 F	30[1]	-
Relative density	6.92 lb/gal [2]	
Heat content	18,400 Btu / lb (LHV)	
% sulfur	<0.5 [2]	0.5 [3]
% nitrogen	0.025 - 0.030	
% ash	negligible	0.01 [1]

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit.

ATTACHMENT MC-EU2-J2

FUEL ANALYSIS
PROPANE ANALYSIS

Parameter	Typical Value
heat content	90,500 Btu/gal
% sulfur	negligible
% nitrogen	0.8% by volume
% ash	negligible

ATTACHMENT MC-EU2-J4

DESCRIPTION OF STACK SAMPLING FACILITIES

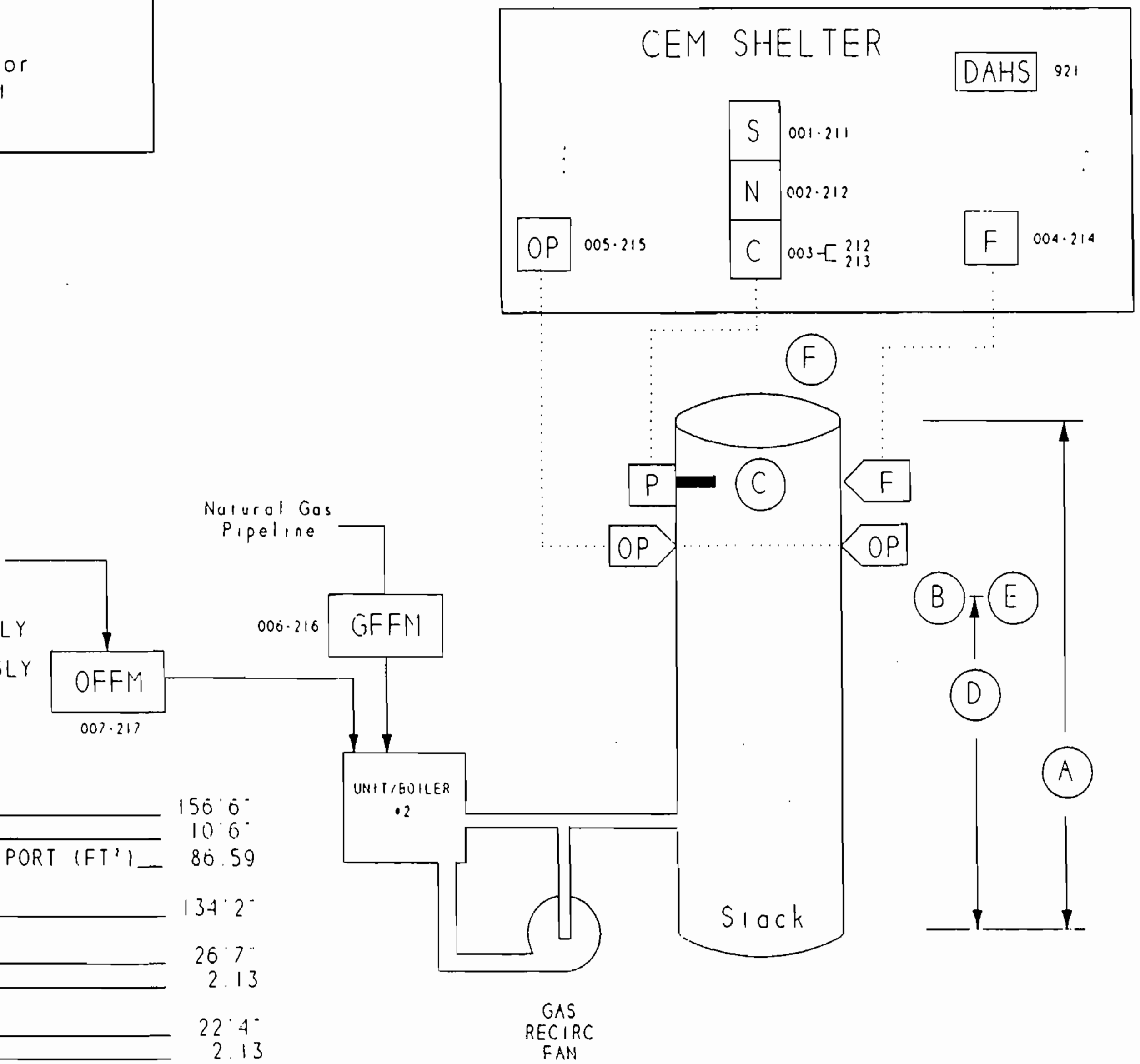
ATTACHMENT #2

PAGE 2 OF 3 PAGES

Schematic Diagram for Unit 2 for
C.D. McIntosh Jr. Power Plant

B:\GCADD\U2CEM

C.D. McIntosh Jr. Plant
ORIS Code: 676
NADB Boiler ID: 2



OFFM FOR USE IN CALCULATING Fc ONLY
WHILE FIRING OIL AND GAS SIMULTANEOUSLY

MONITOR LOCATION INFORMATION

A. STACK HEIGHT ABOVE GRADE (FT)	156'6"
B. STACK DIAMETER AT TEST PORT	10'6"
C. INSIDE CROSS-SECTIONAL AREA AT TEST PORT (FT^{2})	86.59
D. TEST PORT ELEVATION	
1. ABOVE GRADE (FT)	134'2"
2. ABOVE LAST DISTURBANCE	
A. FEET	26'7"
B. STACK DIAMETERS	2.13
3. PRIOR TO NEXT DISTURBANCE	
A. FEET	22'4"
B. STACK DIAMETERS	2.13
E. LOCATION OF SAMPLE PROBE. GASEOUS EXTRACTION PROBE IS IN SAME PLANE AS TEST PORT. OPACITY PROBE AT 1.0 FT. ABOVE SAMPLE PROBE ELEVATION.	
F. INSIDE CROSS-SECTIONAL AREA AT FLUE EXIT (FT^{2})	86.59

ATTACHMENT MC-EU2-J5

COMPLIANCE TEST REPORT

CATALYST
AIR MANAGEMENT, INC.

AIR QUALITY TESTING SERVICES

CITY OF LAKELAND
C.D. McINTOSH POWER PLANT
UNIT 2

EMISSIONS TEST REPORT

Catalyst Air Management, Inc.
Report Number 138-053

July 15, 2002

1.0 Introduction

Catalyst Air Management, Inc. (Catalyst) was contracted by the City of Lakeland to perform the annual NOx and Particulate compliance testing for Unit 2 at C.D. McIntosh Power Plant.

The sampling program was conducted June 11, 2002. The testing was performed by Messers. Mike Taylor, Thomas Gaines and Kevin Garbett of Catalyst, with the assistance of personnel assigned by the City of Lakeland. Mr. John Guiseppi of the City of Lakeland coordinated plant operation during the testing.

2.0 Summary of Test Results

A summary of test results developed by this source sampling program is presented in Tables 1 through 4. The summary tables are presented as follows:

TABLE 1
Summary of Particulate Emissions
C.D McIntosh Unit 2

Parameter	Emission Rate (lb/mmBtu)	Permit (lb/mmBtu)
NOx	0.25	0.30
Particulate	0.05	0.10

TABLE 2
Summary of Visible Emissions
C.D. McIntosh Unit 2

Source	Average VE (%)	Highest 6 min (%)	Permitted (%)
Unit 2	1.0	3.1	20

3.0 Results of Testing

The individual test run results are shown in Tables 3 and 4, and are tabulated in Appendix 1. The results indicate that Unit 2 is in compliance with the emission limits of Permit No. 1050004-009-AV.

TABLE 3
ISOKINETIC SUMMARY
Particulate

Client: **City of Lakeland**
Plant: **McIntosh Unit 2**
Location: **Stack**

Run Number:	**1**	**2**	**3**
Date:	6/11/02	6/11/02	6/11/02
Run Time: Start	7:11	8:30	9:45
End	8:15	9:36	10:51
Unit Load (MW):	105	103	105
Unit Load (MMBTU/HR)):	1051.4	1037.4	1063.2
DN - Nozzle Diameter:	0.250	0.250	0.250
Pbar - Barometric Pressure:	29.9	29.90	29.90
TT - Sampling Time:	60	60	60
VM - Meter Volume:	62.144	57.673	59.112
TM - Avg. Meter Temp (F):	77	85	91
PM - Avg. Delta H (in. of H2O):	3.053	2.996	3.004
Y - Meter Calibration Factor:	1.00	1.00	1.00
VMSTD - Std. Gas Volume (SCF):	61.476	56.234	57.041
Vlc - Volume Water Collected:	140	131	128
%M - Percent Moisture:	9.7	9.9	9.6
Bws - Mole Fraction, Dry:	0.097	0.099	0.096
%CO2 - Carbon Dioxide, Dry:	11.8	11.9	12.3
%O2 - Oxygen, Dry:	5.6	5.6	5.2
%EA - Excess Air	34.6	34.6	31.4
MD - Dry Molecular Weight:	30.11	30.13	30.18
MS - Wet Molecular Weight:	28.94	28.93	29.01
A - Stack Area, SQ.FT:	86.59	86.59	86.59
PS - Static Press. (in. of Hg):	29.95	29.95	29.95
TS - Stack Temp. (F):	198	201	202
CP - Pitot Coefficient:	0.84	0.84	0.84
VS - Stack Gas Velocity (AFPS):	65.1	64.7	64.8
QS - Stack Gas Volume (DSCFM):	245,195	242,108	242,951
QA - Stack Gas Volume (ACFM):	338,048	335,952	336,492
%I - Isokinetic Ratio:	106.2	98.4	99.5
Mg - Catch weight:	85.0	78.6	147.1
Gr/DSCF - Emission Concentration:	0.021	0.022	0.040
LB/MMBtu - Emission Concentration:	0.038	0.039	0.070

Average Gr/DSCF	0.028
Average LB/Mmbtu	**0.049**

TABLE 4
NOx SUMMARY
EPA Method 7E

Client: City of Lakeland
Plant: McIntosh
Unit: 2
Location: Stack

	Run 1	Run 2	Run 3
Date	6/11/02	6/11/02	6/11/02
Start Time	7:11	8:30	9:45
End Time	8:11	9:30	10:45
Measured NOx Concentration (ppm)	177.88	182.35	169.71
Avg Zero Bias Check (ppm)	1.19	1.22	1.55
Upscale Calibration Gas (ppm)	123.4	123.4	123.4
Avg Upscale Bias Check (ppm)	128.5	124.85	124.10
Corrected NOx Concentration (ppm)	171.3	180.8	169.3
Corrected O2 (%)	5.6	5.6	5.2
Corrected CO2 (%)	11.8	11.9	12.3
F-factor	1420	1420	1420
NOx Emissions (lb/mmBtu)	0.246	0.258	0.233
Average NOx Emissions (lb/mmBtu)		**0.25**	

VISIBLE EMISSION OBSERVATION FORM

No. 00001

COMPANY NAME
CITY OF LAKELAND - MC INTOSH POWER PLT

TREET ADDRESS
3030 E. LAKE PARKER DR

ITY: LAKELAND
STATE: FL
ZIP: 33805

HONE (KEY CONTACT): 863-834-6666
SOURCE ID NUMBER: 1050004-011-AV GUID 005

PROCESS EQUIPMENT: UNIT-2 BOILER
OPERATING MODE: ON LINE

ONTROL EQUIPMENT: NONE
OPERATING MODE: N/A

ESCRIBE EMISSION POINT
STACK EXIT - FAR WEST STACK

EIGHT ABOVE GROUND LEVEL: ≈150'
HEIGHT RELATIVE TO OBSERVER: Start ≈150' End ≈150'

DISTANCE FROM OBSERVER: art ≈500' End ≈500'
DIRECTION FROM OBSERVER: Start WNW End WNW

ESCRIBE EMISSIONS
Start STACK GAS & HEAT End

MISSION COLOR: art WHT End WHT
IF WATER DROPLET PLUME: Attached ☐ NA Detached ☐

POINT IN THE PLUME AT WHICH OPACITY WAS DETERMINED
Start STACK EXIT End STACK EXIT

ESCRIBE PLUME BACKGROUND
Start SKY & CLOUDS End SKY / CLOUDS

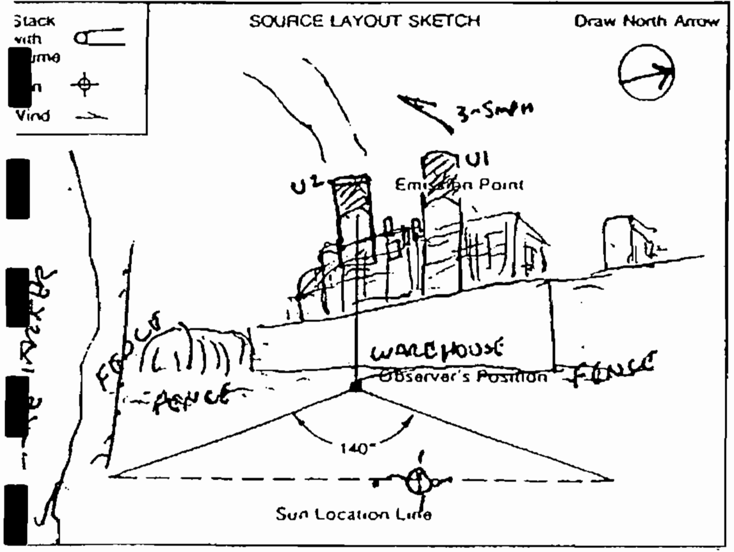
BACKGROUND COLOR: art BLUE/WHT End
SKY CONDITIONS: Start SCATTERED End SCATTERED

NO SPEED: Start 3-5 End —
WIND DIRECTION FROM: Start ENE End

MBIENT TEMP: art 86° End —
WET BULB TEMP: 77°
RH, percent: 66%

SOURCE LAYOUT SKETCH

Draw North Arrow



DITIONAL INFORMATION
HIGH SET ≈ 3.125
NORMAL OPERATING MODE ≈ $\frac{A}{E2}$ = 13.4°

OBSERVATION DATE: 11 JUN 2002
START TIME CEM: 0830
END TIME CEM: 0900

SEC / MIN	0	15	30	45	COMMENTS
31	0	5	0	5	
32	5	5	0	5	
33	5	0	5	0	
34	5	5	0	5	
35	0	0	5	5	
36	5	5	0	5	
37	0	5	0	5	
38	0	5	0	5	
39	5	0	5	0	
40	0	0	0	0	
41	5	0	0	0	
42	0	5	0	5	
43	0	0	0	0	
44	5	0	0	0	
45	0	0	0	0	
46	0	0	0	0	
47	0	0	0	0	
48	0	0	0	0	
49	0	0	0		
50	5	0	5	0	
51	0	0	0	0	
52	0	0	5	0	
53	0	0	0	0	
54	5	5	0	5	
55	5	5	0	0	
56	0	0	0	0	
57	0	0	5	0	
58	0	0	0	0	
59	0	0	0	0	
60	0	0	5	0	

OBSERVER'S NAME (PRINT): JOHN GUISEPPI

OBSERVER'S SIGNATURE
DATE: 11 JUN 2002

ORGANIZATION: CITY OF LAKELAND

CERTIFIED BY: EASTERN TECHNICAL ASSOCIATES
DATE: 2/14/2002

CONTINUED ON VEO FORM NUMBER: 0 0 0 0 2

MAR-6-2003 03:16P FROM: TO:913523366603383409 P:7

VISIBLE EMISSION OBSERVATION FORM

No. 00002

OMPANY NAME
TY OF LAKELAND - MC INTOSH POWER PLT

REET ADDRESS
3030 E. LAKE PARKER DR

ITY: LAKELAND
STATE: FL
ZIP: 33805

ONE (KEY CONTACT): 63-834-6666
SOURCE ID NUMBER: 1050004-011-AV GUID 005

ROCESS EQUIPMENT: NIT-2 BOILER
OPERATING MODE: ON LINE

NTROL EQUIPMENT: NONE
OPERATING MODE: N/A

SCRIBE EMISSION POINT
STACK EXIT - FAR WEST STACK

GHT ABOVE GROUND LEVEL: ≈ 150'
HEIGHT RELATIVE TO OBSERVER: Start ≈ 150' End ≈ 150'

ISTANCE FROM OBSERVER: ≈ 500' End ≈ 500'
DIRECTION FROM OBSERVER: Start WNW End WNW

SCRIBE EMISSIONS
tart STACK EXHAUST End STACK EXHAUST

SSION COLOR: WHT End WHT
IF WATER DROPLET PLUME: Attached ☐ N/A Detached ☐

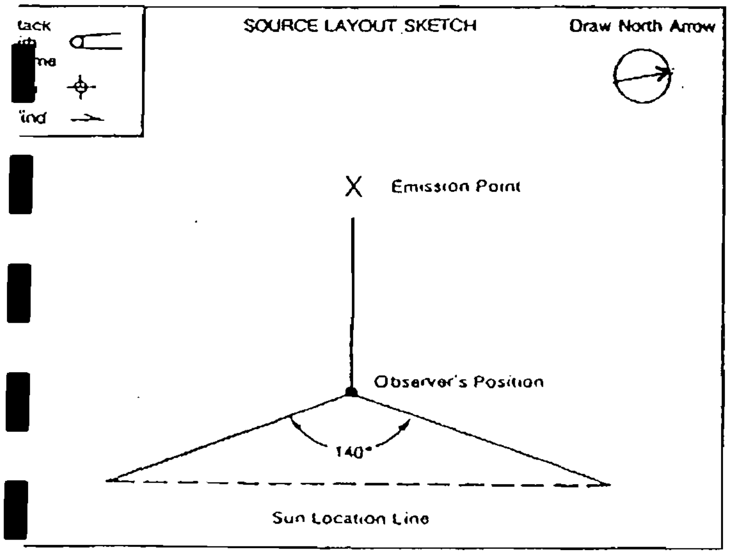
OINT IN THE PLUME AT WHICH OPACITY WAS DETERMINED
tart STACK EXIT End STACK EXIT

SCRIBE PLUME BACKGROUND
tart SKY / CLOUDS End SKY / CLOUDS

ACKGROUND COLOR: BLUE/WHT End BLUE/WHT
SKY CONDITIONS: Start SCATTERED End SCATTERED

D SPEED: tart — End 3-5
WIND DIRECTION: Start — End ENE

BIENT TEMP: — End 87.1
WET BULB TEMP: 75.8
RH, percent: 57.6%



DITIONAL INFORMATION
DRAWING ON 00001

NORMAL OPERATING MODE ≈ 82 =

OBSERVATION DATE: 11 JUN 2002
START TIME: 0901
END TIME: 0931

SEC / MIN	0	15	30	45	COMMENTS
31	0	0	0	0	
32	5	0	0	0	
33	0	0	0	5	
34	0	0	0	5	
35	0	0	0	0	
36	0	0	5	0	
37	0	0	0	0	
38	0	0	0	0	
39	5	0	5	0	
40	5	0	0	0	
41	0	0	0	0	
42	0	0	0	0	
43	0	0	0	0	
44	5	0	0	0	
45	5	0	0	0	
46	0	5	0	0	
47	0	0	0	0	
48	0	0	5	0	
49	0	0	0	0	
50	0	0	0	0	
51	0	0	0	0	
52	0	0	0	0	
53	0	0	0	0	
54	0	0	0	0	
55	0	0	0	0	
56	0	0	0	0	
57	0	5	0	0	
58	0	0	0	0	
59	0	0	0	0	
60	0	0	5	0	

OBSERVER'S NAME (PRINT): JOHN GUISEPPI

OBSERVER'S SIGNATURE
DATE: 11 JUN 2002

ORGANIZATION: CITY OF LAKELAND

CERTIFIED BY: EASTERN TECHNICAL ASSOCIATES
DATE: 2/14/2002

CONTINUED ON VEO FORM NUMBER: ~~00000~~

BEST AVAILABLE COPY

McIntosh Power Plant

Unit-2

#6 Low Sulfur Fuel Oil

11 Jun 2002

Heat Input

Run Times	Fuel Flow Average		Heating Value	Heat Input
EST 07:11 - 08:11 CEM	Fuel Oil Flow Average	56693.7 Lb/Hr	18546 BTU/#	1051.4 MMBtu/Hr
			Average % Heat Input for the Total Runs =	94.30%
			Average MW for the Total Runs =	105

Run Times	Fuel Flow Average		Heating Value	Heat Input
EST 08:30 - 09:30 CEM	Fuel Oil Flow Average	55937.3 Lb/Hr	18546 BTU/#	1037.4 MMBtu/Hr
			Average % Heat Input for the Total Runs =	93.04%
			Average MW for the Total Runs =	103

Run Times	Fuel Flow Average		Heating Value	Heat Input
EST 09:45 - 10:45 CEM	Fuel Oil Flow Average	57328.1 Lb/Hr	18546 BTU/#	1063.2 MMBtu/Hr
			Average % Heat Input for the Total Runs =	95.35%
			Average MW for the Total Runs =	105

Prepared by John Guiseppi

CATALYST AIR MANAGEMENT, INC.
Heat Input and SO2 lb/mmBtu Calculations
City of Lakeland - C.D. McIntosh Plant

Unit 2

OIL ANALYSIS

SO2

Sulfur = 0.66 %
Density = 7.935 lb/gal
Heating Value = 18546 Btu/lb

SO2 (calculated) = 0.712 lb/mmBtu

Heat Input

	fuel (lb/hr)	heat input (mmBtu/hr)
Average	56,653.0	1050.7

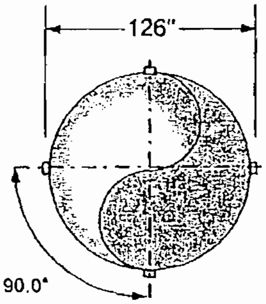
Average Heat Input (calculated) = 1050.7 mmBtu/hr

Maximum Permitted Heat Input = 1115.0 mmBtu/hr
Minimum Test Heat Input = 1003.5 mmBtu/hr

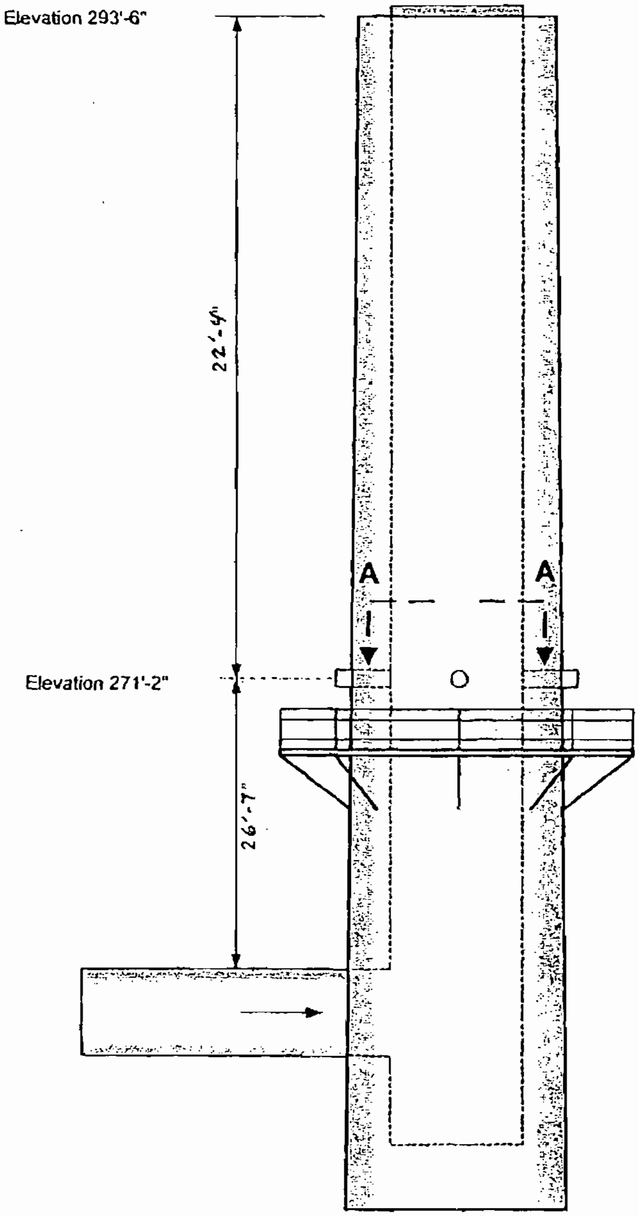
Catalyst Air Management, Inc.

TRAVERSE POINTS (Typ 4 Ports)
(Inches) from inside of stack.

1. 2.6"
2. 8.4"
3. 14.9"
4. 22.3"
5. 31.5"
6. 44.9"



SECTION A - A



TITLE
CITY OF LAKELAND - C.D. McINTOSH POWER PLANT

DESCRIPTION
UNIT NO. 2 STACK TEST PORT CONFIGURATION

DATE
6/2/99

SCALE
NONE

DRAWN BY
MJ TAYLOR

REVISED

ATTACHMENT MC-EU2-J6

PROCEDURES FOR STARUP AND SHUTDOWN

ATTACHMENT MC-EU2-J6

PROCEDURES FOR STARTUP AND SHUTDOWN MINIMIZING EXCESS EMISSIONS

Startup of the fossil-fuel boilers begins when fuel (propane, natural gas or No. 2 fuel oil) is introduced into one or more burners within the boiler and lighted (commencement of combustion). Startup is complete and steady-state operation begins when the combustion process has stabilized and the megawatt load on the unit is stable and above 10-15 percent load.

Shutdown of the fossil-fuel boilers begins when unit megawatt load is decreased to below 10-15 percent of maximum and continues until the final burner gun is removed from service.

Emissions may be detected during all modes of boiler operation by various continuous emissions monitors. Continuous monitors are currently in place for NO_x, CO_2, SO_2, flow and opacity. Audible and visual alarms are activated whenever the permitted value for opacity is approached.

Countermeasures that may be taken in the event of excess emissions include, but are not limited to:

- Burner elevation loading
- Proper excess air adjustments
- Recognizing and removal of faulty burners
- Fuel oil temperature adjustments
- Proper and timely operation of boiler cleaning devices
- Removal of the unit from system-dispatch mode (load control)
- Reduction of unit megawatt load
- Stopping and restarting of boiler cleaning devices
- Lowering load ramp rate
- Pressure rate changes
- Placing boiler controls on manual
- Adjusting burner dampers to increase windbox/furnace air pressure

Knowledge of the appropriate countermeasures to take when excess emissions occur is a part of the routine operator training for those who operate the boilers. Topics include current permit limits, maximum

allowable duration of excess emissions, appropriate countermeasures for excess emissions, duty to notify, and fuels and combustion training.

ATTACHMENT MC-EU2-J11

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT MC-EU2-J11

ALTERNATIVE METHODS OF OPERATION FOSSIL FUEL STEAM GENERATOR

The fossil fuel steam generator can operate on both natural gas and fuel oil (No. 6 through No. 2 fuel oil). The maximum sulfur content in the fuel oil shall not exceed 2.5 percent. The No. 2 fuel oil is used as pilot fuel during startup, shutdown, and malfunctions. This unit can operate for the entire year at varying loads (i.e., 8,760 hours 0 to 100 percent load) and can fire fuels, alone or in combination, with no restrictions on hours of operation.

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 3 – Fossil-Fuel-Fired Steam Generator (FFFSG)

4. Emissions Unit Identification Number: [ ] No ID
ID: **006** [ ] ID Unknown

5. Emissions Unit Status Code: **A**	6. Initial Startup Date: **01 Sep 1982**	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [X]

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

This emission unit is a coal-fired steam-generating unit which also co-fires refuse-derived fuel and petroleum coke.

Emissions Unit Control Equipment

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

PM – Electrostatic Precipitator (ESP), followed by
SO_2 – Flue Gas Desulfurization (FGD) system.
NO_X – Low NO_X burners (LNB).

2. Control Device or Method Code(s): **10, 67, 24**

Emissions Unit Details

1. Package Unit:
Manufacturer: Model Number:

2. Generator Nameplate Rating: **364** 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:			3,640	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):

Emission unit co-fires coal and refuse-derived fuel (RDF) and coal/petroleum coke and/or RDF. Unit is also authorized to burn residual oil and gas. Heat input based on fuel flow sampling.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment MC-FI-C12	

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? **S003**

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: **250** feet

7. Exit Diameter: **18** feet

8. Exit Temperature: **107** °F

9. Actual Volumetric Flow Rate: **1,260,536** acfm

10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm

12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **409.3** North (km): **3106.3**

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

For oil firing with no SO_2 scrubbing, the estimated exit gas temperature = 250°F

Flow = 1,093,685 ACFM

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

Segment Description and Rate: Segment 1 of 7

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

Coal

2. Source Classification Code (SCC): **1-01-001-01**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate: **159.6**	5. Maximum Annual Rate: **1,398,096**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **3.3**	8. Maximum % Ash: **16**	9. Million Btu per SCC Unit: **23**

10. Segment Comment (limit to 200 characters):

See Attachment MC-EU3-E10

Segment Description and Rate: Segment 2 of 7

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

Coal and RDF (90/10 heat input basis)

2. Source Classification Code (SCC): **1-01-001-01**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate: **184.1**	5. Maximum Annual Rate: **1,612,716**	6. Estimated Annual Activity Factor:
10. Maximum % Sulfur: **2.9**	8. Maximum % Ash: **17**	9. Million Btu per SCC Unit: **22**

10. Segment Comment (limit to 200 characters):

See Attachment MC-EU3-E10

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

Segment Description and Rate: Segment 3 of 7

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Oil**		
2. Source Classification Code (SCC): **1-01-004-01**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **24,268**	5. Maximum Annual Rate: **212,584**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.73**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**
10. Segment Comment (limit to 200 characters): **See Attachment MC-EU3-E10**		

Segment Description and Rate: Segment 4 of 7

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Oil/Refuse (90/10 heat input basis)**		
2. Source Classification Code (SCC): **1-01-004-01**	3. SCC Units: **1,000 Gallons Burned**	
4. Maximum Hourly Rate: **21.84**	5. Maximum Annual Rate: **192,318**	6. Estimated Annual Activity Factor:
11. Maximum % Sulfur: **0.73**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **150**
10. Segment Comment (limit to 200 characters): **See Attachment MC-EU3-E10**		

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

Segment Description and Rate: Segment 5 of 7

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Coal/Petroleum Coke (80/20 weight basis)**		
2. Source Classification Code (SCC): **1-01-001-01**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate: **152.6**	5. Maximum Annual Rate: **1,336,776**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **3.3**	8. Maximum % Ash: **15**	9. Million Btu per SCC Unit: **24**
10. Segment Comment (limit to 200 characters): **See Attachment MC-EU3-E10.**		

Segment Description and Rate: Segment 6 of 7

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Coal/Petroleum Coke/RDF (80/20 weight basis at 90 percent of heat input; RDF at 10 percent of heat input).**		
2. Source Classification Code (SCC): **1-01-001-01**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate: **168.8**	5. Maximum Annual Rate: **1,478,688**	6. Estimated Annual Activity Factor:
12. Maximum % Sulfur: **3.3**	8. Maximum % Ash: **15**	9. Million Btu per SCC Unit: **22**
10. Segment Comment (limit to 200 characters): **See Attachment MC-EU3-E10.**		

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

Segment Description and Rate: Segment 7 of 7

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

Natural Gas

2. Source Classification Code (SCC): **1-01-006-01**		3. SCC Units: **Million Cubic Feet**
4. Maximum Hourly Rate: **3.56**	5. Maximum Annual Rate: **31,139**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit: **1,024**

10. Segment Comment (limit to 200 characters):

Natural gas or propane only or in combination with any other fuels or fuel combinations listed in Attachment MC-EU3-E10.

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:
13. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:

10. Segment Comment (limit to 200 characters):

F. EMISSIONS UNIT POLLUTANTS

(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	010		EL
SO_2	067		EL
NO_X	024		EL
CO			NS
VOC			NS
H107	067		NS
HCl	067		NS
PM_{10}	010		NS

Emissions Unit Information Section 3 of 8 **Unit 3**

Pollutant Detail Information Page 1 of 3 **Particulate Matter - Total**

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: **99.1**
3. Potential Emissions: **273** lb/hour **1,196** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.075 lb/mmBtu** Reference: **Permit PSD-FL-008(B)**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **0.075 lb/mmBtu x 3,640 mmBtu/hr = 273 lb/hr** **273 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 1,196 TPY**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Based on oil/RDF firing.**	

Allowable Emissions Allowable Emissions 1 of 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.070 lb/mmBtu**	4. Equivalent Allowable Emissions: **254** lb/hour **1,116** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 5, 5B, or 17, if greater than 400 hours.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emission limit based on PSD-FL-008(B) for oil firing.**	

Emissions Unit Information Section 3 **of** 8 **Unit 3**

Pollutant Detail Information Page 1 **of** 3 **Particulate Matter - Total**

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

Potential/Fugitive Emissions

1. Pollutant Emitted:	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 4

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.075 lb/mmBtu**	4. Equivalent Allowable Emissions: **273** lb/hour **1,196** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 5, 5B, or 17, if greater than 400 hours.**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Allowable emission limit based on PSD-FL-008(B) for oil/RDF firing.**	

Emissions Unit Information Section 3 **of** 8 **Unit 3**

Pollutant Detail Information Page 1 **of** 3 **Particulate Matter - Total**

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

Potential/Fugitive Emissions

1. Pollutant Emitted:

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 3 of 4

1. Basis for Allowable Emissions Code:
OTHER

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.05 lb/mmBtu

4. Equivalent Allowable Emissions:
182 lb/hour **797.2** tons/year

5. Method of Compliance (limit to 60 characters):
Annual stack test; EPA Method 5, 5B, or 17.

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):
Allowable emission limit based on PSD-FL-008(B) for coal/petroleum coke/RDF firing and coal/RDF firing.

Emissions Unit Information Section 3 **of** 8 **Unit 3**

Pollutant Detail Information Page 1 **of** 3 **Particulate Matter - Total**

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

Potential/Fugitive Emissions

1. Pollutant Emitted:

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 4 of 4

1. Basis for Allowable Emissions Code:
OTHER

2. Future Effective Date of Allowable Emissions:

3. Requested Allowable Emissions and Units:
0.044 lb/mmBtu

4. Equivalent Allowable Emissions:
160 lb/hour **702** tons/year

5. Method of Compliance (limit to 60 characters):

Annual stack test; EPA Method 5, 5B, or 17.

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

Allowable emission limit based on PSD-FL-008(B) for coal firing and coal/petroleum coke firing.

Emissions Unit Information Section 3 of 8 **Unit 3**

Pollutant Detail Information Page 2 of 3 **Sulfur Dioxide**

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: **85**

3. Potential Emissions: **4,368** lb/hour **19,131.8** tons/year	4. Synthetically Limited? [ ]

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

6. Emission Factor: **1.2 lb/mmBtu** Reference: **Permit PSD-FL-008(B)**	7. Emissions Method Code: **0**

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

1.2 lb/mmBtu x 3,640 mmBtu/hr = 4,368 lb/hr
4,368 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 19,132 ton/yr

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

Based on solid fuel combustion and maximum heat input of 3,640 mmBtu/hr oil firing.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **1.2 lb/mmBtu (3-hour average)**	4. Equivalent Allowable Emissions: **4,368** lb/hour **19,132** tons/year

5. Method of Compliance (limit to 60 characters):

Annual stack test; EPA Methods 6 and 6B.

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

See Attachment MC-EU3-E10. Allowable based on 40 CFR Part 60, Subpart D for solid fuel firing.

Emissions Unit Information Section 3 **of** 8 **Unit 3**

Pollutant Detail Information Page 2 **of** 3 **Sulfur Dioxide**

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

Potential/Fugitive Emissions

1. Pollutant Emitted:	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 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.8 lb/mmBtu (3-hour average)**	4. Equivalent Allowable Emissions: **2,912** lb/hour **12,755** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel analysis test**	
6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters): **Allowable emission limit based on 40 CFR Part 60, Subpart D for oil firing.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted:	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 3 of 3

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.718 lb/mmBtu**	4. Equivalent Allowable Emissions: **2,613.5** lb/hour **11,447** tons/year
5. Method of Compliance (limit to 60 characters): **CEM**	
6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters): **Allowable when blends of petroleum coke with other fuels are co-fired, based on 30-day rolling average [PSD-FL-008(B)].**	

Emissions Unit Information Section 3 of 8 **Unit 3**

Pollutant Detail Information Page 3 of 3 **Nitrogen Oxides**

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: **2,548** lb/hour **11,160** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.7 lb/mmBtu** Reference: **40 CFR Part 60.44**	7. Emissions Method Code:

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

0.7 lb/mmBtu x 3,640 mmBtu/hr = 2,548 lb/hr
2,548 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton = 11,160 ton/yr

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

Potential emissions based on coal firing.

Allowable Emissions Allowable Emissions 1 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.7 lb/mmBtu (3-hour average)**	4. Equivalent Allowable Emissions: **2,548** lb/hour **11,160** tons/year

5. Method of Compliance (limit to 60 characters):

Annual stack test; EPA Method 7, 7A, 7C, 7D, or 7E

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

Allowable emissions based on solid fossil fuel or solid fossil fuel and wood residue.

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

Potential/Fugitive Emissions

1. Pollutant Emitted:	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 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.30 lb/mmBtu (3-hour average)**	4. Equivalent Allowable Emissions: **1,092** lb/hour **4,783** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 7, 7A, 7C, 7D, or 7E**	
6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters): **Allowable emissions based on liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.**	

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

Potential/Fugitive Emissions

1. Pollutant Emitted:	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 3 of 3

1. Basis for Allowable Emissions Code: **RULE**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.2 lb/mmBtu (3-hour average)**	4. Equivalent Allowable Emissions: **728** lb/hour **3,189** tons/year
5. Method of Compliance (limit to 60 characters): **Annual stack test; EPA Method 7, 7A, 7C, 7D, or 7E**	
6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters): **Allowable emissions based on gaseous fossil fuel.**	

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: **20** % Exceptional Conditions: **27** %
Maximum Period of Excess Opacity Allowed: **6** min/hour

4. Method of Compliance:

Annual VE testing; EPA Method 9

5. Visible Emissions Comment (limit to 200 characters):

Title V Permit 1050004-011-AV

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

Continuous Monitoring System: Continuous Monitor 1 of 8

1. Parameter Code: **EM**	2. Pollutant(s): **SO_2**

3. CMS Requirement: [X] Rule [ ] Other

4. Monitor Information:
Manufacturer: **Advanced Pollution Inst.**
Model Number: **152** Serial Number: **139/176 and 172/156**

5. Installation Date: **09 Nov 1994**	6. Performance Specification Test Date:

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

CEM required pursuant to 40 CFR Part 75, PSD-FL-008.

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype:
VE99

2. Basis for Allowable Opacity:
[X] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: % Exceptional Conditions: **100** %
Maximum Period of Excess Opacity Allowed: **60** min/hour

4. Method of Compliance:

None

5. Visible Emissions Comment (limit to 200 characters):

Excess VE emissions allowed under FDEP Rule 62-210.700(1) and 40 CFR 60.8(c), and 60.11(c) for 2 hours (120 minutes) per 24-hour period for startup, shutdown, and malfunction.

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

Continuous Monitoring System: Continuous Monitor 2 of 8

1. Parameter Code: **EM**

2. Pollutant(s): **NO_X**

3. CMS Requirement: [X] Rule [ ] Other

4. Monitor Information:
Manufacturer: **Advanced Pollution Inst.**
Model Number: **252** Serial Number: **165 and 136**

5. Installation Date:
09 Nov 1994

6. Performance Specification Test Date:

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

CEM required pursuant to 40 CFR Part 75, PSD-FL-008.

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:

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 3 of 8

1. Parameter Code: **VE**	2. Pollutant(s):

3. CMS Requirement: [X] Rule [ ] Other

4. Monitor Information:
Manufacturer: **United Science Inc.**
Model Number: **500C** Serial Number: **0993688**

5. Installation Date: **09 Nov 1994**	6. Performance Specification Test Date:

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

CEM required pursuant to 40 CFR Part 75 and PSD-FL-008.

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:

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 4 of 8

1. Parameter Code: **CO_2**	2. Pollutant(s):

3. CMS Requirement: [X] Rule [ ] Other

4. Monitor Information:
Manufacturer: **California Instruments**
Model Number: **3300** Serial Number: **N3L2487T and N3L2490T7**

5. Installation Date: **09 Nov 1994**	6. Performance Specification Test Date:

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

CEM required pursuant to 40 CFR Part 75.

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:

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 5 of 8

1. Parameter Code: **FLOW**	2. Pollutant(s):

3. CMS Requirement: [X] Rule [ ] Other

4. Monitor Information:
Manufacturer: **United Science Ultraflow**
Model Number: **100** Serial Number: **1001060**

5. Installation Date: **10 Nov 1995**	6. Performance Specification Test Date:

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

Flow monitor required pursuant to 40 CFR Part 75.

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
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 6 of 8

1. Parameter Code: **EM**	2. Pollutant(s): **SO_2**
3. CMS Requirement:	[**X**] Rule [ ] Other
4. Monitor Information: Manufacturer: **Lear Siegler** Model Number: **SM 810**	Serial Number: **29259M**
5. Installation Date: **17 Sep 1982**	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): **CEM required pursuant to 40 CFR 60.45.**	

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:

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 7 of 8

1. Parameter Code: **VE**	2. Pollutant(s):

3. CMS Requirement: [**X**] Rule [ ] Other

4. Monitor Information:
Manufacturer: **Lear Seigler**
Model Number: **CM50** Serial Number: **291230**

5. Installation Date: **17 Sep 1982**	6. Performance Specification Test Date:

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

COM required pursuant to 40 CFR 60.45.

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

1. Visible Emissions Subtype:	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
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 8 of 8

1. Parameter Code: O_2	2. Pollutant(s):
3. CMS Requirement:	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Lear Siegler Model Number: RM41	Serial Number:
5. Installation Date: 17 Sep 1982	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters): O_2 required pursuant to 40 CFR 60.45.	

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

Supplemental Requirements

1. Process Flow Diagram
   [X] Attached, Document ID: MC-EU3-J1 [ ] Not Applicable [ ] Waiver Requested

2. Fuel Analysis or Specification
   [X] Attached, Document ID: MC-EU3-J2 [ ] Not Applicable [ ] Waiver Requested

3. Detailed Description of Control Equipment
   [X] Attached, Document ID: MC-EU3-J3 [X] Not Applicable [ ] Waiver Requested

4. Description of Stack Sampling Facilities
   [X] Attached, Document ID: MC-EU3-J4 [ ] Not Applicable [ ] Waiver Requested

5. Compliance Test Report
   [X] Attached, Document ID: MC-EU3-J5
   [ ] Previously submitted, Date: ______________
   [ ] Not Applicable

6. Procedures for Startup and Shutdown
   [X] Attached, Document ID: MC-EU3-J6[ ] 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: MC-EU3-J11 [ ] 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: MC-FI-C13 [ ] Not Applicable

14. Compliance Assurance Monitoring Plan
[X] Attached, Document ID: MC-EU3-J14 [X] Not Applicable

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

[X] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
Attached, Document ID: MC-EU1-J15

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

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

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

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

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

[ ] Not Applicable

ATTACHMENT MC-EU3-E10

SEGMENT COMMENT

ATTACHMENT MC-EU3-E10

SEGMENT COMMENTS

For Segment #1, Coal; the maximum hourly rates and percent sulfur will vary depending upon coal source but will not exceed 3.3 percent. Heat content is based on maximum hourly rate of tons per hour (TPH) and maximum heat input rating for unit of 3,640 MMBtu/hr.

For Segment #2, Coal and RDF (90/10 heat input basis); there is another SCC of 1-01-012-02. The maximum hourly rates and percent sulfur will vary depending upon mixture. Sulfur content assumption - coal and RDF blended to a sulfur content of 2.9 percent with coal at 3.3 percent sulfur and RDF at 0.1 percent sulfur. Maximum hourly rate calculated using tons/hour (TPH) 143.7 TPH coal and 40.4 TPH RDF. Heat content of mixture based on the maximum heat input rating for unit of 3,640 MMBtu/hr. Typical heat contents for coal and RDF are 24.6 and 9 MMBtu/ton, respectively.

For Segment #3 Heat content based on maximum hourly rate (1,000 gal) and maximum heat input rating for unit of 3,640 MMBtu/hr. Distillate oil (1-01-005-01) is used for unit startup and load stabilization (could be used as primary fuel-fired). Maximum sulfur based on firing oil without FGD System. Higher sulfur oil allowed with FGD.

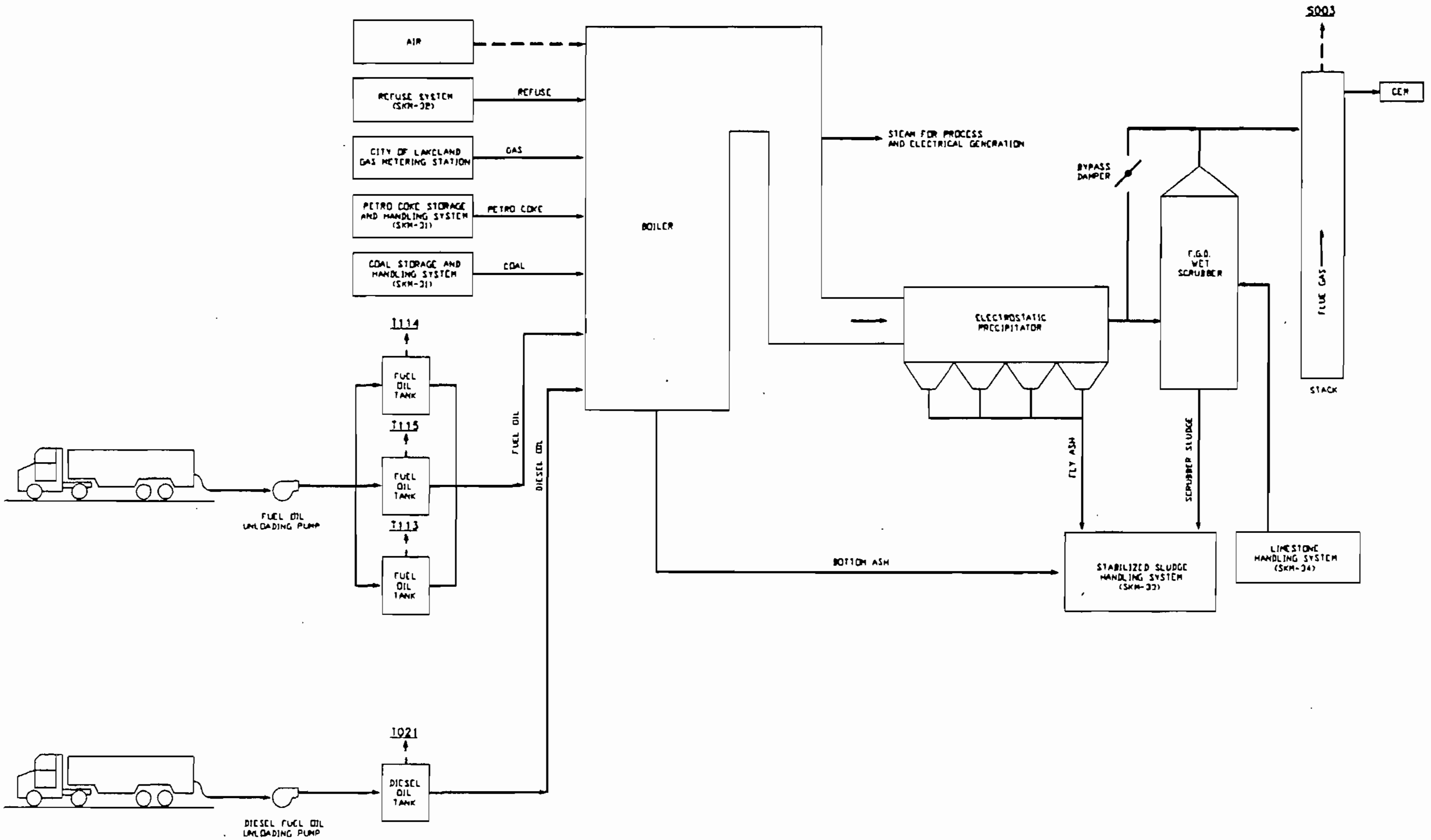
For Segment #4, Oil and RDF (90/10 heat input basis); there is another SCC of 1-01-012-02. The maximum hourly rates and percent sulfur will vary depending upon mixture. Oil and RDF (40.4 tons/hour and 353,904 tons/year) blended to a sulfur content of 0.73 percent. Heat content of mixture based on the maximum heat input rating for unit of 3,640 MMBtu/hr. RDF has heat value of 9 MMBtu/ton. Higher sulfur oil is allowed if FGD is used to meet SO_2 limit.

For Segment #5, Coal and Petroleum coke (80/20 weight basis); the maximum hourly rates and percent sulfur will vary depending upon mixture. Coal and petroleum coke will be blended to a maximum sulfur content of 3.3 percent. Typical sulfur content of petroleum coke is 5 percent. Maximum hourly rate calculated using 122.1 TPH coal and 30.5 TPH petroleum coke. Heat content of mixture based on the maximum heat input rating for unit of 3,640 MMBtu/hr. Heat contents of coal and petroleum coke are 22.81 and 20.0 MMBtu/ton.

For Segment #6, Coal, Petroleum Coke and RDF (80/20 weight basis at 90% of heat input; RDF at 10% of heat input); the maximum hourly rates and percent sulfur will vary depending upon mixture. Coal, RDF, and petroleum coke will be blended to a maximum sulfur content of 3.3 percent. Maximum hourly rate calculated using 100.9 TPH coal, 40.4 TPH RDF, and 27.5 TPH petroleum coke. Heat content of mixture based on the maximum heat input rating for unit of 3,640 MMBtu/hr.

ATTACHMENT MC-EU3-J1

PROCESS FLOW DIAGRAM



REV. NO.	BY	DATE	APPR.	REVISION
3	MG	5-28-96	HP	ISSUED FOR TITLE V
2	MG	5-15-96	HP	CHANGE TITLE & ADDED LIMESTONE
1	MG	8-9-95		DELETED T116

LAKELAND
ELECTRIC
& WATER

DESCRIPTION

LAKELAND ELECTRIC & WATER UTILITIES
C.D. McINTOSH POWER PLANT
UNIT NO. 3
PROCESS FLOW DIAGRAM

DIVISION PRODUCTION ENGINEERING
ENGINEER PATTERSON
DRN. BY: MGIEGER
DATE 9-19-94
APPR. BY:

CAD
SCALE NONE
PROJ. NO. AIR PERMIT
DWG. NO. LMC-EU3-L1/SKM-27
REV. 3

SIZE B

ATTACHMENT MC-EU3-J2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT MC-EU3-J2

FUEL ANALYSIS
COAL

Parameter	Typical Value	Maximum[a], Minimum[b], or Design[c] Value
heat content (Btu/lb)	13,000	11,200[b] - 12,174[c]
% sulfur	1.0 - 1.5	2.5[c] - 3.3[a]
% nitrogen	1.3 - 1.7	1.54%[c] (dry)
% ash	5 - 13	16.3[c]

ATTACHMENT MC-EU3-J2

FUEL ANALYSIS
RDF

Parameter	Typical Value
heat content (Btu/lb)	4,300 - 6,340
% moisture	5 - 49
% ash	3 - 35
% sulfur	0.1

From laboratory analysis

ATTACHMENT MC-EU3-J2

FUEL ANALYSIS
PETROLEUM COKE

Parameter	Typical Value
heat content (Btu/lb)	14,000
% sulfur	5
% ash	0.35

From laboratory analysis

ATTACHMENT MC-EU3-J2

FUEL ANALYSIS
NATURAL GAS ANALYSIS

Parameter	Typical Value	Max Value
Relative density	0.58 (compared to air)	
heat content	950 - 1124 Btu/cu ft. (HHV)	
% sulfur	0.43 grains/CCF [1]	1 grain/100 CF
% nitrogen	0.8% by volume	
% ash	negligible	

Note: The values listed are "typical" values based upon information supplied by Florida Gas Transmission (FGT). However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

---

[1] Data from laboratory analysis

ATTACHMENT MC-EU3-J2

FUEL ANALYSIS
NO. 6 FUEL OIL

Parameter	Typical Value	Max Value
API gravity @ 60 F	8[1]	-
Relative density	8.2 lb/gal [2]	
Heat content	18,300 Btu / lb (HHV)	
% sulfur	0.7 [2]	0.725 [3]
% nitrogen	0.25 - 0.50	
% ash	negligible	0.01 [1]

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit based on 0.8 lb/MMBtu for oil firing only; when using FGD system, or when co-firing with gas, sulfur content can be as high as 2.5 percent.

ATTACHMENT MC-EU3-J2

FUEL ANALYSIS
NO. 2 FUEL OIL

Parameter	Typical Value	Max Value
API gravity @ 60 F	30[1]	-
Relative density	6.92 lb/gal [2]	
Heat content	18,400 Btu / lb (LHV)	
% sulfur	<0.5 [2]	0.5
% nitrogen	0.025 - 0.030	
% ash	negligible	0.01 [1]

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from fuel procurement specification

[2] Data from laboratory analysis

ATTACHMENT MC-EU3-J2

FUEL ANALYSIS
PROPANE ANALYSIS

Parameter	Typical Value
heat content	90,500 Btu/gal
% sulfur	negligible
% nitrogen	0.8% by volume
% ash	negligible

ATTACHMENT MC-EU3-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

ATTACHMENT MC-EU3-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

McIntosh Unit 3 has air pollution control equipment for nitrogen oxides (NO_x), particulate matter (PM) and sulfur dioxide (SO_2). The information that follows present a description of the equipment controlling these pollutants.

NITROGEN OXIDES

NO_x is controlled using boiler design and dual register burners to achieve an emission rate of no greater than 0.7 lb/mmBtu. The burner zone has a heat release rate of 370 kBtu/hr-ft^2, which reduces the NO_x emissions to 0.7 lb/mmBtu or less. The boiler and burner was manufactured by Babcock and Wilcox (B&W).

PARTICULATE MATTER

The PM from the combustion of fuels in Unit 3 is controlled by an electro-static precipitator (ESP). The ESP has the following design parameters:

Plate Height - 47.6 ft.
Number of Casings - 2
Field Depth - 16.4 ft
Number of Lanes per Casing - 50
Number of Fields/Casing - 5
Effective Area/Plate - 1,559.3 ft^2
Total Effective Area - 779,700 ft^2

SULFUR DIOXIDE

SO_2 is controlled using a wet limestone scrubbing system. The scrubber is of a tray tower type consisting of two absorber modules. Each module provides a 55-percent capacity of total unit output. The components of the scrubbing system are listed below:

Quencher - Flue gases exiting the ESP inters the quenchers for each absorber, which condition the flue gas. Each absorber has a venturi-type quencher with a throat of 27 feet long and 5 feet wide. The quench water is recirculated from the quencher sump.

Absorber Tray Tower - After adiabatic saturation in the quencher, the gases pass up through the tray tower absorber for SO_2 removal. The limestone slurry is introduced at the top of the tray absorber from a series of spray headers. The flow is countercurrent through the 36 ft wide (diameter) absorber.

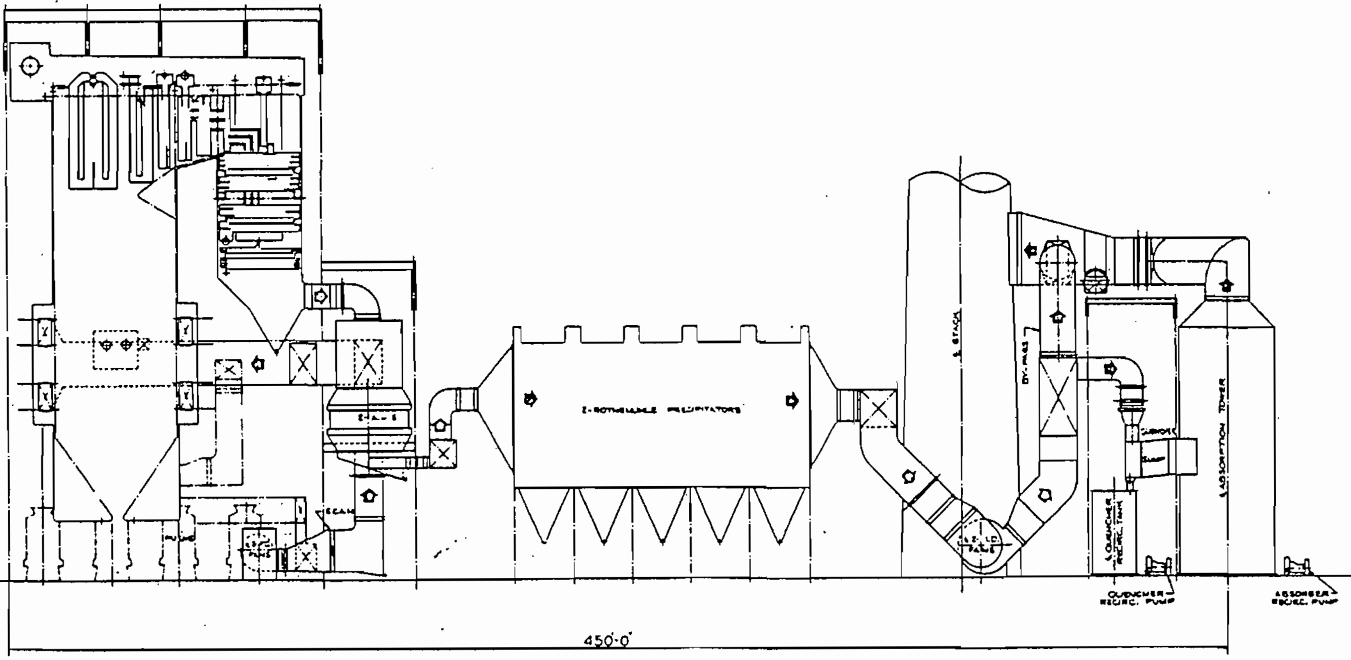
Demister - Before exiting the absorber, aerosols in the flue gas are removed in a z-shaped demister made from reinforced fiberglass material.

Associated Equipment - Supporting the operation of the scrubber are the following equipment: absorber recirculation tank, quencher recirculation tank, and quencher and absorber recirculation pumps. The scrubber is equipped with a hot air reheat system (steam coil) and a bypass flue. The latter bypasses flue gases around the absorber system and mixes with air exiting the absorber tower. This increases the exit gas temperatures. A continuous emission monitoring system is installed to assure compliance with the SO_2 emission limit.

Additional equipment/processes supporting the scrubber system include limestone slurry preparation system, slurry storage and transfer system, and dewatering system.

The scrubber is of a Babcock & Wilcox design.

P12-4640 - 710

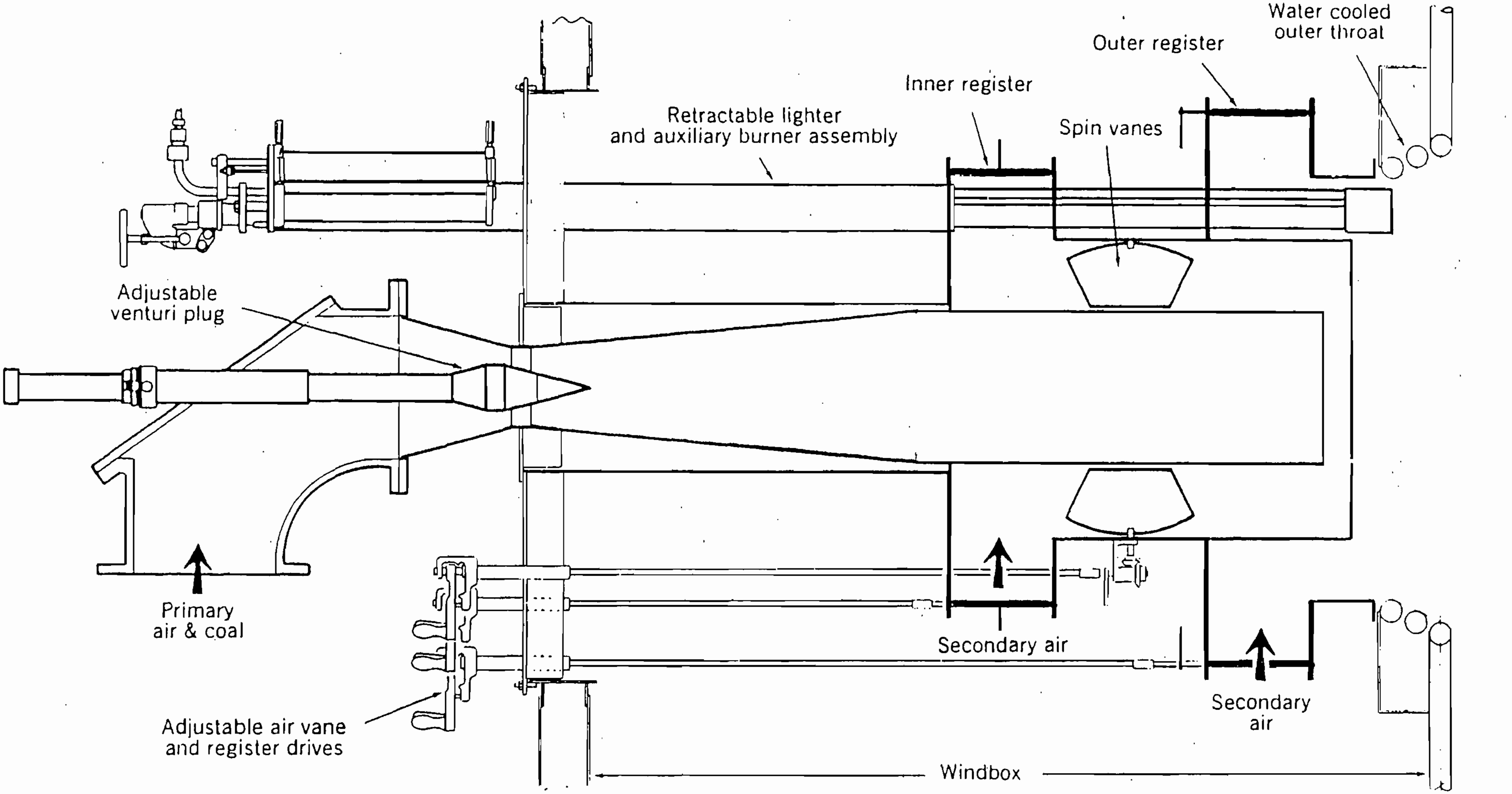


Babcock & Wilcox
POWER GENERATION

DEPARTMENT OF ELECTRIC AND WATER UTILITIES
CITY OF LAKELAND
CHAS. T. MAIN, INC.
C.D. McINTOSH PLANT, UNIT NO. 3

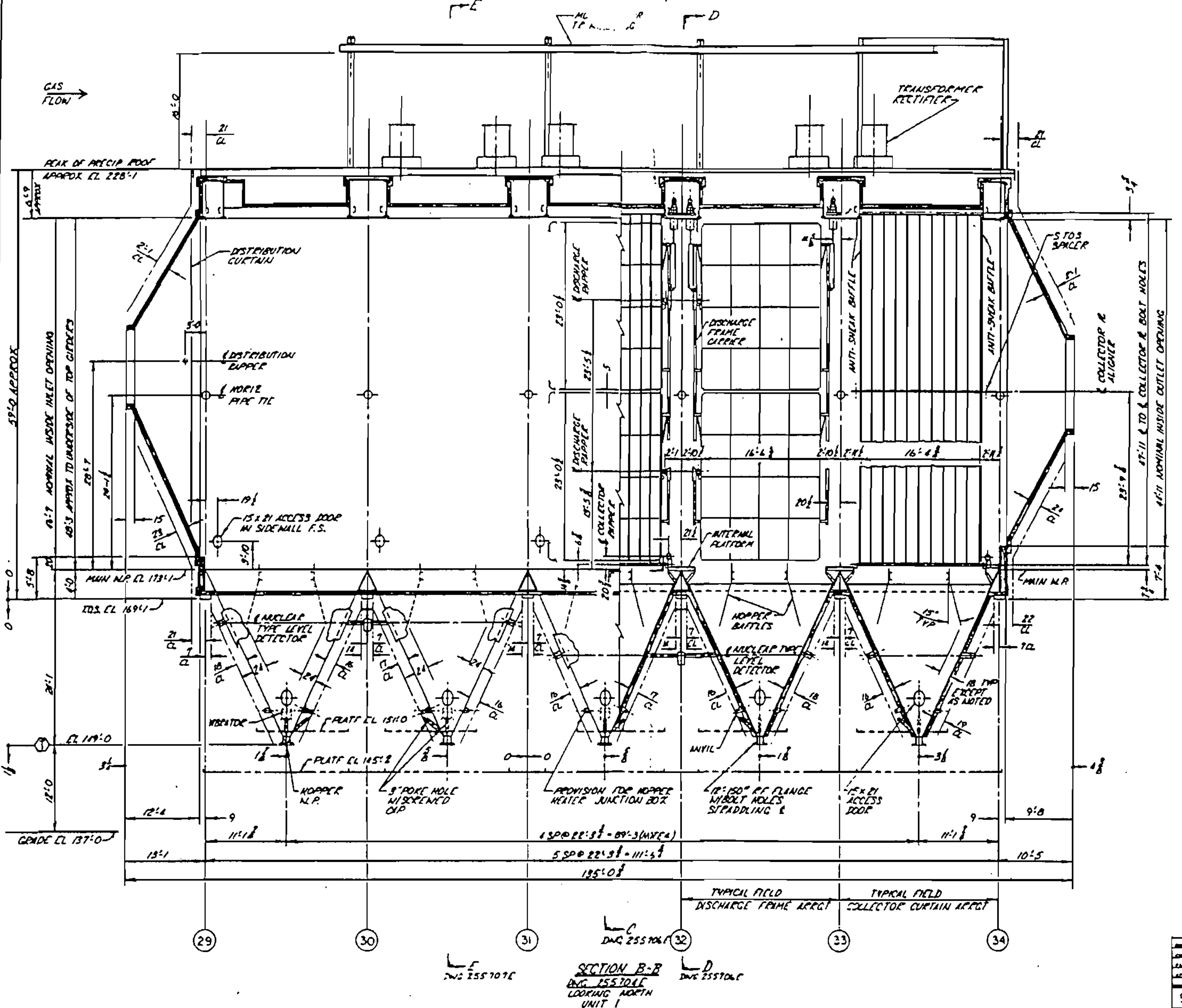
CITY OF LAKELAND
THE BABCOCK & WILCOX COMPANY

P12-4640 - 710



Dual register burner

Figure 1



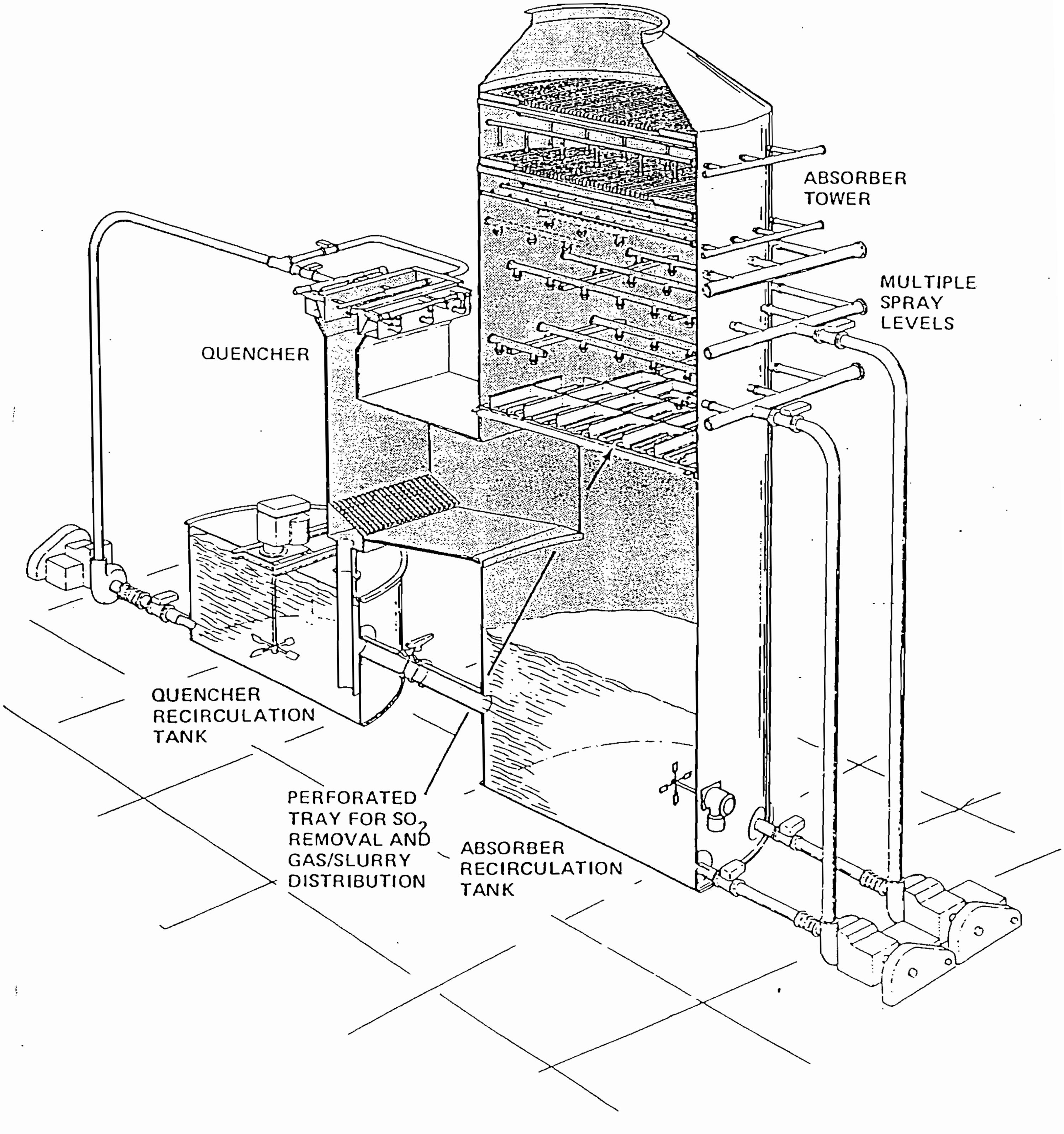
SECTION B-B
DWG 255704E
LOOKING NORTH
UNIT 1

NOTES & REFERENCE DWGS:
SEE DWG 255702E

DEPARTMENT OF
ELECTRIC AND WATER UTILITIES
CITY OF LAKELAND
CHAS. T. MAIN, INC.
C. D. McINTOSH PLANT, UNIT NO. 3

D. DILVARD	GENERAL ARRANGEMENT PRECIPITATOR SECTIONAL SIDE VIEW
KERCHEFF	
547-0023	255705E

SULFUR DIOXIDE ABSORBER TRAY TOWER MODULE



ATTACHMENT MC-EU3-J4

DESCRIPTION OF STACK SAMPLING FACILITIES

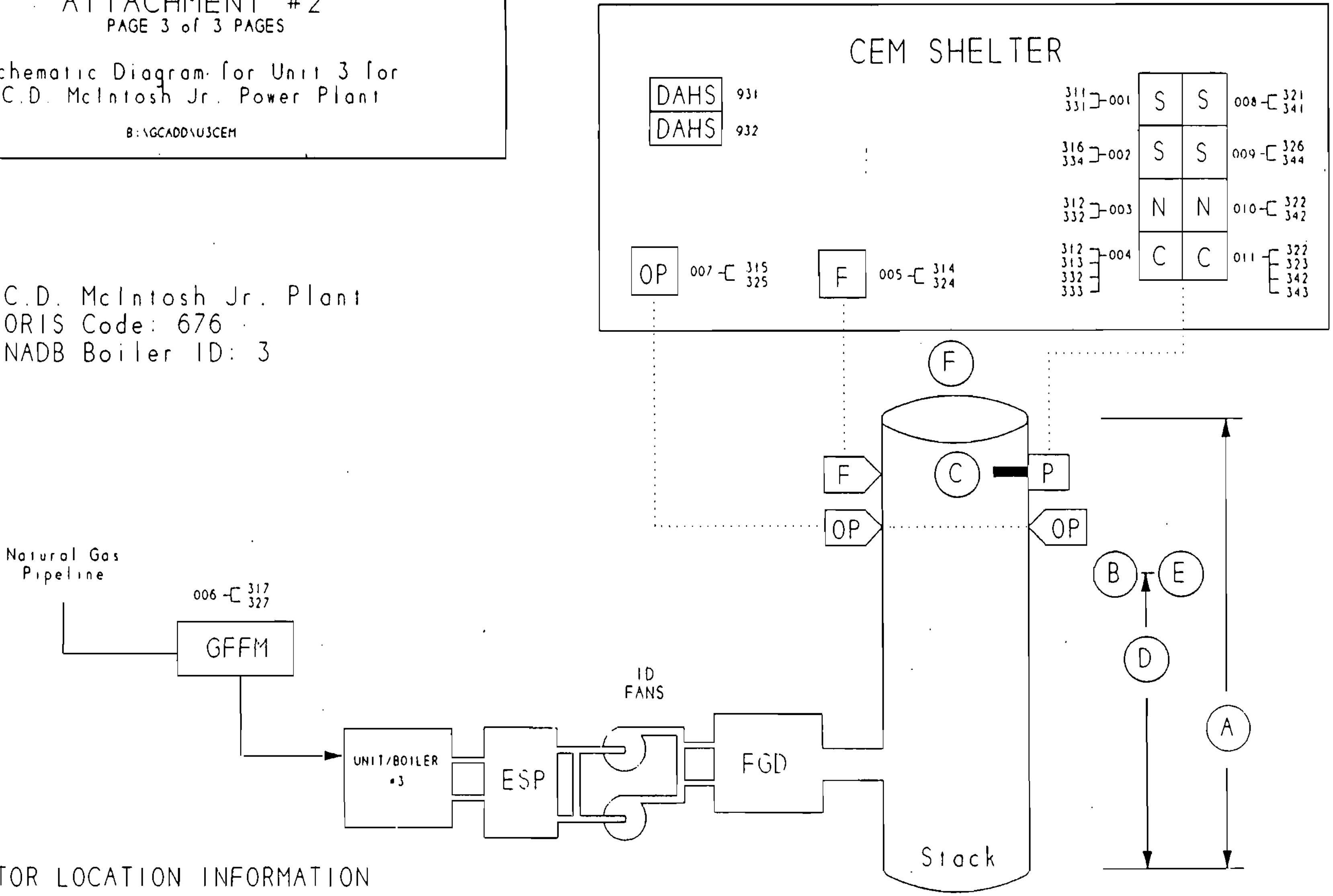
ATTACHMENT #2

PAGE 3 of 3 PAGES

Schematic Diagram for Unit 3 for
C.D. McIntosh Jr. Power Plant

B:\GCADD\U3CEM

C.D. McIntosh Jr. Plant
ORIS Code: 676
NADB Boiler ID: 3



MONITOR LOCATION INFORMATION

A. STACK HEIGHT ABOVE GRADE (FT) 252'
B. STACK DIAMETER AT TEST PORT 18'7"
C. INSIDE CROSS-SECTIONAL AREA AT TEST PORT (FT^2) 271.28
D. TEST PORT ELEVATION
  1. ABOVE GRADE (FT) 222'9"
  2. ABOVE LAST DISTURBANCE
    A. FEET 82'9"
    B. STACK DIAMETERS 4.45
  3. PRIOR TO NEXT DISTURBANCE
    A. FEET 29'3"
    B. STACK DIAMETERS 1.57
E. LOCATION OF SAMPLE PROBE. GASEOUS EXTRACTION PROBE IS IN SAME PLANE AS TEST PORT. OPACITY PROBE AT 2'6" BELOW SAMPLE PROBE ELEVATION.
F. INSIDE CROSS-SECTIONAL AREA AT FLUE EXIT (FT^2) 254.47

ATTACHMENT MC-EU3-J5

COMPLIANCE TEST REPORT

CATALYST
AIR MANAGEMENT, INC.

AIR QUALITY TESTING SERVICES

CITY OF LAKELAND
C.D. McINTOSH POWER PLANT
UNIT 3

EMISSIONS TEST REPORT

Catalyst Air Management, Inc.
Report Number 138-055

July 19, 2002

1.0 Introduction

Catalyst Air Management, Inc. (Catalyst) was contracted by the City of Lakeland to perform the annual compliance testing for particulate, NOx and SO_2 emissions at C.D. McIntosh Power Plant Unit 3, in Lakeland, FL.

The sampling program was conducted June 12 and 13, 2002. The testing was performed by Mike Taylor, Thomas Gaines and Kevin Garbett of Catalyst, with the assistance of personnel assigned by the City of Lakeland. Mr. John Guisseppi of Lakelend coordinated plant operation during the testing.

2.0 Summary of Test Results

A summary of test results developed by this source sampling program are presented in Tables 1 through 4.

The summary tables are presented as follows:

Table	Description	Page
1	Summary of Emissions	1
2	Summary of Visible Emissions	1
3	Isokinetic Summary – Particulate	3
4	NOx/SO_2 Summary	3

TABLE 1

Summary of Emissions

C.D. McIntosh Power Plant

Unit 3

Parameter	Average (lb/mmBtu)	Permitted (lb/mmBtu)
Particulate	0.03	0.05
NOx	0.50	0.70
SO_2	0.61	1.20

TABLE 2

Summary of Visible Emissions

C.D. McIntosh Power Plant

Unit 3

Source	Average VE (%)	Highest 6 min (%)	Permitted (%)
Unit 3	10.6	14.4	20

TABLE 3
ISOKINETIC SUMMARY
Particulate

Client: **City of Lakeland**
Plant: **McIntosh Unit 3**
Location: **Stack**

Run Number:	1	2	3
Date:	6/13/02	6/13/02	6/13/02
Run Time: Start	6:37	8:04	9:48
End	7:52	9:20	11.02
Unit Load (MW):	360	360	360
Unit Load (MMBTU/HR)):	3442.3	3442.3	3442.3
DN - Nozzle Diameter:	0.188	0.188	0.188
Pbar - Barometric Pressure:	29.88	29.88	29.88
TT - Sampling Time:	60	60	60
VM - Meter Volume:	46.178	46.859	47.27
TM - Avg. Meter Temp (F):	85	91	96
PM - Avg. Delta H (in. of H2O):	2.046	2.046	2.058
Y - Meter Calibration Factor:	1.01	1.01	1.01
VMSTD - Std. Gas Volume (SCF):	45.358	45.230	45.529
Vlc - Volume Water Collected:	122	177	157
%M - Percent Moisture:	11.2	15.6	14.0
Bws - Mole Fraction, Dry:	0.112	0.156	0.140
%CO2 - Carbon Dioxide, Dry:	10.7	10.7	10.7
%O2 - Oxygen, Dry:	9.1	8.9	8.9
%EA - Excess Air	75.4	72.2	72.2
MD - Dry Molecular Weight:	30.08	30.07	30.07
MS - Wet Molecular Weight:	28.72	28.19	28.38
A - Stack Area, SQ.FT:	271.84	271.84	271.84
PS - Static Press. (in. of Hg):	29 92	29.92	29.92
TS - Stack Temp. (F):	180	182	182
CP - Pitot Coefficient:	0.84	0.84	0.84
VS - Stack Gas Velocity (AFPS):	88.7	89.6	89.4
QS - Stack Gas Volume (DSCFM):	1,059,200	1,014,784	1,031,461
QA - Stack Gas Volume (ACFM):	1,446,518	1,461,109	1,457,471
%I - Isokinetic Ratio:	100.7	104.8	103.8
Mg - Catch weight:	49.4	18.0	21.7
Gr/DSCF - Emission Concentration:	0.017	0.006	0.007
LB/MMBtu - Emission Concentration:	0.042	0.015	0.018

Average Gr/DSCF 0.010
Average LB/Mmbtu **0.025**

TABLE 4
NOx/SO_2 SUMMARY

Client: City of Lakeland
Plant: McIntosh
Unit: 3
Location: STACK

	Run 1	Run 2	Run 3
Date	6/12/02	6/12/02	6/12/02
Start Time	9:15	10:35	12:20
End Time	10:15	11:35	13:20
Measured NOx Concentration (ppm)	253.75	243.43	242.67
Avg Zero Bias Check (ppm)	1.72	1.78	1.885
Upscale Calibration Gas (ppm)	246.8	246.8	246.8
Avg Upscale Bias Check (ppm)	247.5	248.7	249.8
Corrected NOx Concentration (ppm)	253.1	241.5	239.7
Corrected O2 (%)	9.1	8.9	8.9
Corrected CO2 (%)	10.8	10.7	10.9
F-factor	9780	9780	9780
NOx Emissions (lb/mmBtu)	0.523	0.491	0.488
Average NOx Emissions (lb/mmBtu)		**0.50**	
Measured SO2 Concentration (ppm)	224.01	219.09	205.08
Avg Zero Bias Check (ppm)	1.905	1.57	1.50
Upscale Calibration Gas (ppm)	437.3	437.3	437.3
Avg Upscale Bias Check (ppm)	441.2	438.6	440.3
Corrected NOx Concentration (ppm)	221.1	217.7	202.9
Corrected O2 (%)	9.1	8.9	8.9
Corrected CO2 (%)	10.8	10.7	10.9
F-factor	9780	9780	9780
SO2 Emissions (lb/mmBtu)	0.636	0.616	0.574
Average SO2 Emissions (lb/mmBtu)		**0.61**	

VISIBLE EMISSION OBSERVATION FORM

CUM ↓ No. 00001

COMPANY NAME
CITY OF LAKELAND U3

STREET ADDRESS
MC INTOSH POWER PLANT
3030 E. LAKE PARKER DR

CITY LAKELAND
STATE FL
ZIP 33803

PHONE (KEY CONTACT) 863-834-6600
SOURCE ID NUMBER FDEP V 105004-003-AV

PROCESS EQUIPMENT COAL-FIRED STEAM GENERATOR
OPERATING MODE 360 MW

CONTROL EQUIPMENT PRECIPITATOR & SCRUBBER
OPERATING MODE IN SERVICE

DESCRIBE EMISSION POINT
STACK EXIT

HEIGHT ABOVE GROUND LEVEL 275'
HEIGHT RELATIVE TO OBSERVER Start 275' End 275'

DISTANCE FROM OBSERVER Start 825' End 825'
DIRECTION FROM OBSERVER Start NNW End NNW

DESCRIBE EMISSIONS
Start WHT SMOKE End

EMISSION COLOR Start WHT End
IF WATER DROPLET PLUME Attached ☐ N/A Detached ☐

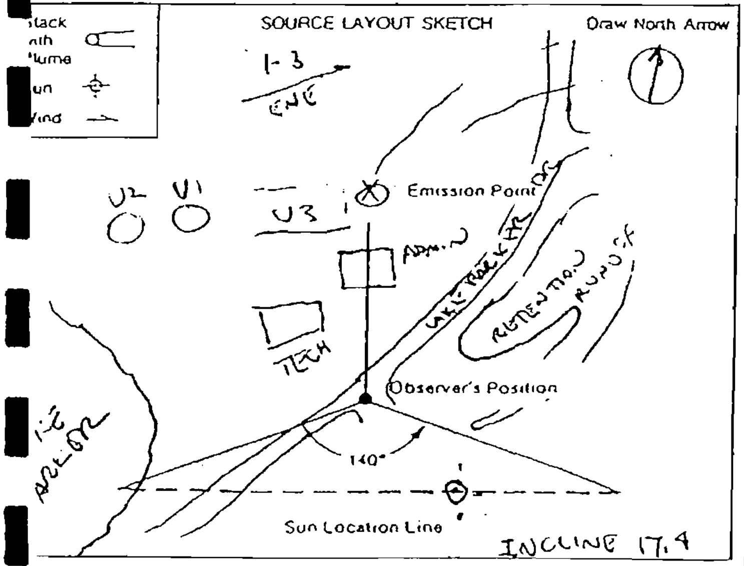
POINT IN THE PLUME AT WHICH OPACITY WAS DETERMINED
Start STACK EXIT End STACK EXIT

DESCRIBE PLUME BACKGROUND
Start BLUE SKY End

BACKGROUND COLOR Start BLUE End
SKY CONDITIONS Start SCATTERED End

WIND SPEED Start 1-3 End
WIND DIRECTION TOWARD Start ENE End

AMBIENT TEMP Start 81.8 End
WET BULB TEMP 76.7
RH, percent 76.9



DITIONAL INFORMATION

0CFR60, APPA METHOD 9
HIGH SET AVG=14.2

OBSERVATION DATE 13 JUN 02
START TIME 0806
END TIME 0835

SEC / MIN	0	15	30	45	COMMENTS
1	10	10	10	10	
2	10	5	10	10	
3	10	5	5	10	
4	10	10	10	10	
5	10	10	15	10	
6	10	10	5	5	
7	5	5	5	5	CLOUDS
8	5	5	5	5	"
9	10	5	5	5	"
10	5	5	5	5	"
11	5	5	10	5	CLOUDS
12	10	10	10	15	
13	15	10	10	15	
14	15	10	10	10	
15	5	5	5	5	
16	5	5	10	10	
17	5	5	5	10	
18	10	10	15	15	
19	15	15	15	15	
20	15	15	15	15	
21	15	15	15	15	
22	10	10	10	10	
23	5	5	5	5	CLOUDS
24	5	5	5	0	"
25	5	5	0	5	"
26	5	5	5	5	CLOUDS
27	5	10	10	10	
28	5	5	5	10	
29	10	15	15	15	
30	10	15	15	15	

OBSERVER'S NAME (PRINT)

OBSERVER'S SIGNATURE JOHN GUISEPPI
DATE 6/13/02

ORGANIZATION
CITY OF LAKELAND

CERTIFIED BY ETA
DATE 14 FEB 02

CONTINUED ON VEO FORM NUMBER 2L 0 0 0 0 1

VISIBLE EMISSION OBSERVATION FORM

CEM No. 00002

COMPANY NAME
CITY OF LAKELAND U3

STREET ADDRESS
MC INTOSH POWER PLANT
3030 E. LAKE PARKER DR

CITY LAKELAND
STATE FL
ZIP 33803

PHONE (KEY CONTACT) 863-834-6600
SOURCE ID NUMBER FDEP V 105004-003-AV

PROCESS EQUIPMENT COAL-FIRED STEAM GENERATOR
OPERATING MODE 360MW

CONTROL EQUIPMENT PRECIPITATOR, & SCRUBBER
OPERATING MODE IN SERVICE

DESCRIBE EMISSION POINT
STACK EXIT

HEIGHT ABOVE GROUND LEVEL 275'
HEIGHT RELATIVE TO OBSERVER Start 275' End 275'

DISTANCE FROM OBSERVER Start 825' End 825'
DIRECTION FROM OBSERVER Start NNW End NNW

DESCRIBE EMISSIONS
Start End WHITE SMOKE

EMISSION COLOR Start End WHT
IF WATER DROPLET PLUME Attached ☐ N/A Detached ☐

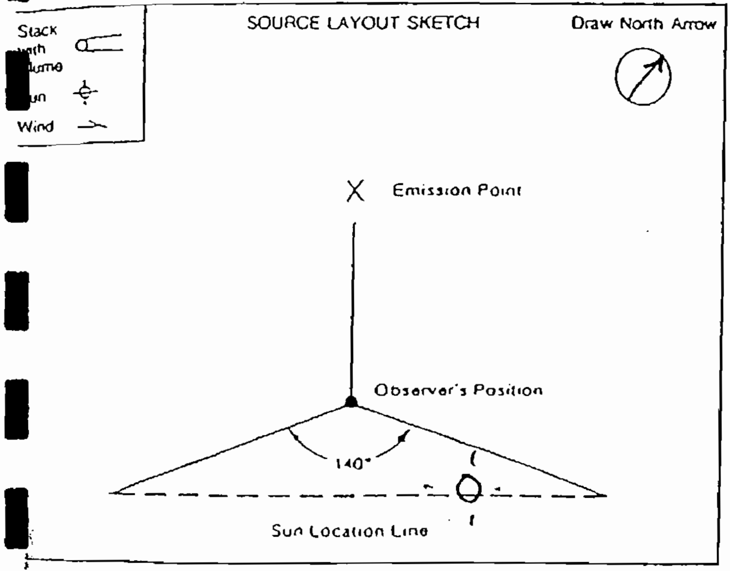
POINT IN THE PLUME AT WHICH OPACITY WAS DETERMINED
Start End STACK EXIT

DESCRIBE PLUME BACKGROUND
Start End BLUE SKY w/CLOUDS

BACKGROUND COLOR Start End BLUE/WHT
SKY CONDITIONS Start End SCATTERED

WIND SPEED Start End 1-3
WIND DIRECTION TOWARD Start End ENE

AMBIENT TEMP Start End 85.3
WET BULB TEMP 74.1
RH, percent 68.0



ADDITIONAL INFORMATION
DRAWING ON Pg 00001
40CFR60, APP.A METHOD 9 HIGH 6MIN AVG=14.2

OBSERVATION DATE 13 JUN 02
START TIME 0836
END TIME 0905

SEC / MIN	0	15	30	45	COMMENTS
1	10	10	15	15	
2	15	15	15	15	
3	15	15	15	10	
4	15	15	10	15	
40	10	10	15	10	
6	10	10	15	10	
7	10	10	10	10	
8	10	10	10	15	
9	15	15	15	15	
45	15	15	15	15	
11	15	15	15	15	
12	10	15	15	15	
13	15	15	10	15	
14	15	15	10	10	
50	10	10	10	10	
16	10	10	10	15	
17	15	15	15	10	
18	15	15	15	10	
19	15	10	10	15	
55	15	10	15	10	
21	15	15	10	15	
22	15	10	15	15	
23	15	15	15	15	
24	10	10	15	10	
00	10	10	15	10	
26	15	10	10	10	
27	15	10	10	10	
28	15	10	10	10	
29	10	5	5	5	CLOUDS
05	10	15	5	15	

OBSERVER'S NAME (PRINT) JOHN GUISEPPI

OBSERVER'S SIGNATURE
DATE 13 JUN 02

ORGANIZATION CITY OF LAKELAND

CERTIFIED BY ETA
DATE 14 FEB 02

CONTINUED ON VEO FORM NUMBER 26

McIntosh Power Plant

Unit-3

Coal, Petcoke and RDF
12-Jun-02

un Averages	Fuels Average			Heating Value		Heat Input	
15 - 13:20	COAL & Petcoke	136.3	Tn/Hr	12487	BTU/#	3402.71	MMBtu/Hr
	RDF	4.66	Tn/Hr	8.5	MMBtu/Tn	39.61	MMBtu/Hr
				Average Total		3442.32	MMBtu/Hr
				Average % Heat Input for Runs		94.57%	

Average MW for the test =	360 MW
Average Fuel Flow (Coal & Coke) for the test =	136.3 Tn/Hr
Average Fuel Flow (RDF) for the test =	4.66 Tn/Hr

Average Heat Input for the Test = 94.57%

COAL KLB/H	
Time	Avg. Flow
9:00	269.3
10:00	269.1
11:00	270.0
12:00	269.5
13:00	277.9
14:00	272.7
15:00	279.0
Avg. Flow	272.5

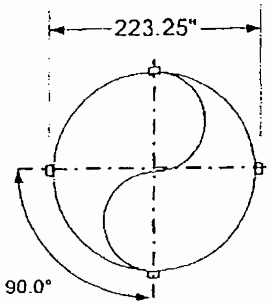
Avg. Tn/Hr 136.3 Tn/Hr

Prepared by John Guiseppi

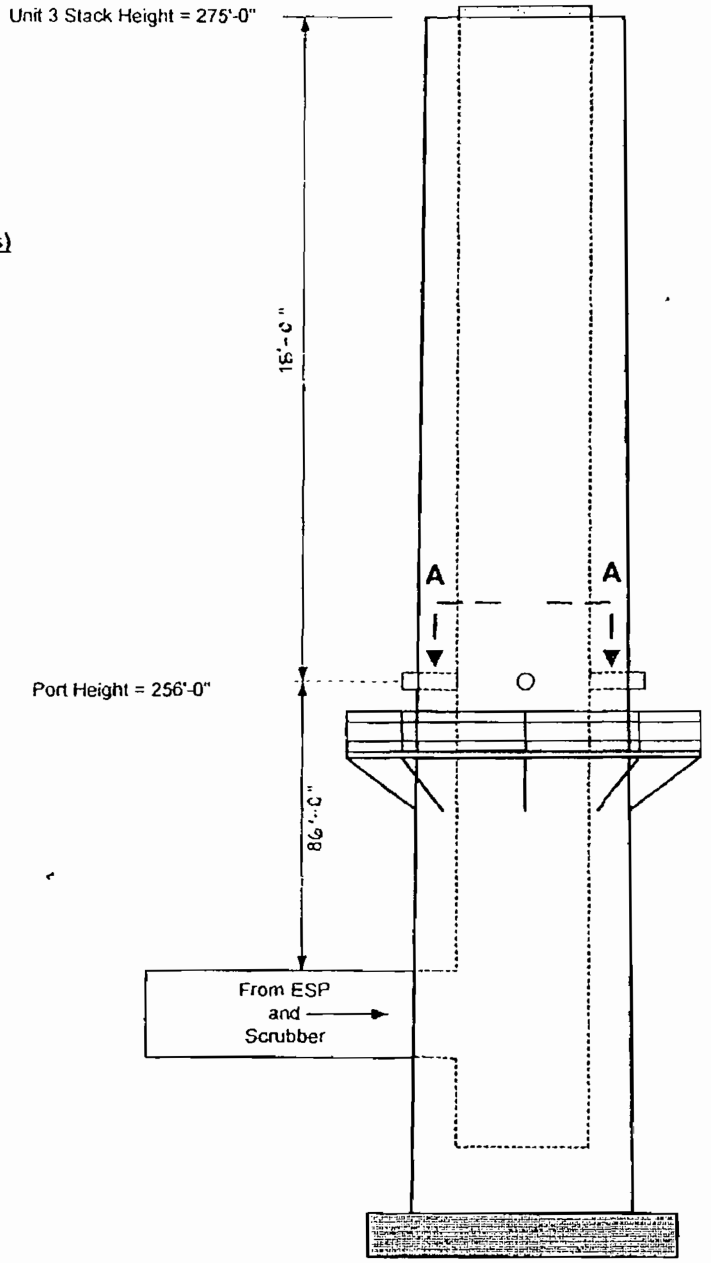
CATALYST
AIR MANAGEMENT, INC.

TRAVERSE POINTS (Typ 4 Ports)
(Inches) from inside of stack.

1. 4.69" + 48" = 52.69"
2. 14.96" + 48" = 62.96"
3. 26.34" + 48" = 74.34"
4. 39.52" + 48" = 87.52"
5. 55.81" + 48" = 103.81"
6. 79.48" + 48" = 127.48"



SECTION A - A



TITLE
CITY OF LAKELAND - C.D. McINTOSH POWER PLANT

DESCRIPTION
UNIT NO. 3 STACK TEST PORT CONFIGURATION

DATE
1/2/99

SCALE
NONE

DRAWN BY
MJ TAYLOR

REVISED

ATTACHMENT MC-EU3-J6

PROCEDURES FOR STARUP AND SHUTDOWN

ATTACHMENT MC-EU3-J6

PROCEDURES FOR STARTUP AND SHUTDOWN MINIMIZING EXCESS EMISSIONS

Startup of the fossil-fuel boilers begins when fuel (No. 2 fuel oil, natural gas or propane) is introduced into one or more burners within the boiler and lighted (commencement of combustion). Startup is complete and steady-state operation begins when the combustion process has stabilized and the megawatt load on the unit is stable and above 10-15 percent load.

Shutdown of the fossil-fuel boilers begins when unit megawatt load is decreased to below 10 percent of maximum and continues until the final burner gun is removed from service.

Emissions may be detected during all modes of boiler operation by various continuous emissions monitors. Continuous monitors are currently in place for NO_x, CO_2, SO_2, flow and opacity. Audible and visual alarms are activated whenever the permitted value for opacity is approached.

Countermeasures which may be taken in the event of excess emissions include, but are not limited to:

- Burner elevation loading
- Pproper excess air adjustments
- Recognizing and removal of faulty burners
- Fuel oil temperature adjustments
- Proper and timely operation of boiler cleaning devices
- Removal of the unit from system-dispatch mode (load control)
- Reduction of unit megawatt load
- Stopping and restarting of boiler cleaning devices
- Lowering load ramp rate
- Pressure rate changes
- Placing boiler controls on manual
- Adjusting burner dampers to increase windbox/furnace air pressure

Knowledge of the appropriate countermeasures to take when excess emissions occur is a part of the routine operator training for those who operate the boilers. Topics include current permit limits, maximum

allowable duration of excess emissions, appropriate countermeasures for excess emissions, duty to notify, and fuels and combustion training.

ATTACHMENT MC-EU3-J11

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT MC-EU3-J11

ALTERNATIVE METHODS OF OPERATION

The unit can be fired with multiple fuels up to 3,640 MMBtu/hour. The following fuels and fuel combinations may be burned:

1. Coal only with FGD
2. Low sulfur fuel oil only (0.5 percent sulfur by weight) with or without FGD
3. Coal and up to 10 percent refuse (based on heat input) with FGD
4. Low sulfur fuel oil and up to 10 percent refuse (based on heat input) with or without FGD
5. Coal and up to 20 percent petroleum coke (based on weight) with FGD
6. Coal and up to 20 percent petroleum coke (based on weight) and 10 percent refuse (based on heat input) with FGD
7. High sulfur fuel oil (>0.5 percent sulfur by weight) consistent with conditions 2.C. or 2.D. of PSD-FL-008(B); with or without FGD
8. Natural gas only, or in combination with any of the other fuels or fuel combinations listed above; with or without FGD

The FGD system can operate from 65 to 90 percent removal.

ATTACHMENT MC-EU3-J14

COMPLIANCE ASSURANCE MONITORING PLAN

COMPLIANCE ASSURANCE MONITORING PLAN
(CAM PLAN)

FOR

C. D. McIntosh, Jr. Power Plant

Lakeland Electric
Polk County, Florida

April, 2003

I. EMISSION UNITS REQUIRING CAM PLANS

A. CAM Rule Applicability Definition

Lakeland Electric was issued a Title V Air Operation Permit (Permit No. 1050004) that was effective January 1, 1999 for their C. D. McIntosh, Jr. Power Plant (McIntosh). This permit has subsequently been revised November 19, 2000 and October 16, 2001 through permit revisions 1050004-009 and 105004-011. The current permit, unless renewed through submittal of an application to the Florida Department of Environmental Protection (FDEP), expires on December 31, 2003. To be considered timely and sufficient, as defined in Rule 62-4.090 of the Florida Administrative Code, renewal application must be submitted no later than 180 days prior to the expiration date of the permit.

As part of these Title V renewal applications EPA, through regulations adopted in Title 40, Part 64 of the Code of Federal Regulations (40 CFR 64), is requiring submittal of Compliance Assurance Monitoring (CAM) Plans. This regulation has been incorporated by reference by FDEP in Rule 62-204.800 and implemented in Rule 62-213.440.

CAM plans are required for all Title V permitted emission units using control devices to meet federally enforceable emission limits or standards with pre-control emissions greater than "major" source thresholds. The term "major" is defined as in the Title V Regulations (40 CFR 70), but applied on a source-by-source basis. However, there are some specific exemptions to the applicability of the CAM Rule.

Specifically exempted from the CAM Rule are emissions units subject to requirements under Stratospheric Ozone Regulations (40 CFR 82), the Acid Rain Program (40 CFR 72), or that are part of an emission cap included in the Title V Permit. Also exempt are emission units subject to New Source Performance Standards (40 CFR 60) and National Emission Standards for Hazardous Air Pollutants (40 CFR 63) promulgated after 11/15/1990, as these sources have equivalent monitoring requirements included as part of the standard.

B. Emissions Units Requiring CAM Plans

A review of emission units at McIntosh was conducted to determine the applicability of the CAM Rule. This evaluation was conducted for each emission unit and pollutant. First, the existence of a "control device" as defined by the CAM Rule was determined on a source-by-source basis for each pollutant. Those emission units without control devices were eliminated from further consideration. The remaining emission units were then evaluated on a pollutant-by-pollutant basis to determine if a control device was used to meet a federally enforceable emission limit or standard. Each pollutant without a federally enforceable emission limit or standard, emitted from a given emission unit, was eliminated from further consideration. Uncontrolled annual emissions were then calculated for each remaining source-pollutant combination. If uncontrolled emissions for a pollutant emitted from a given emission unit source were below major source thresholds as defined by the CAM Rule, that pollutant was not further considered. A summary of the results of this evaluation process is presented in Table 1. Specific exemptions to the applicability of the CAM Rule were also considered in this evaluation.

McIntosh Unit 1 (E.U. ID No. 001)

McIntosh Unit 1 is a forced draft boiler rated at a nominal load of 90 megawatts. The unit is fired with natural gas at a maximum heat input of 985 million Btu per hour (MMBtu/hr) (approximately 970 million cubic feet per hour), or No. 6 fuel oil, having a maximum sulfur content of 2.5 percent by weight, at a maximum heat input rate of 950 MMBtu/hr (approximately 6,300 gallons per hour). This unit is also permitted to burn "on-specification" used oil generated by the City of Lakeland, at a maximum heat input rate of 950 MMBtu/hr. The emissions from this unit are regulated under Acid Rain, Phase II; and Rule 62-296.405, F.A.C., Fossil Fuel Generators with More than 250 MMBtu/hr heat input.

Although Unit 1 has federally enforceable limits for particulate matter, visible emissions, and sulfur dioxide emissions, Unit 1 does not use control devises to meet these limits or standards. Therefore the requirements of CAM are not applicable to Unit 1.

Diesel Engine Peaking Units 1 and 2 (E.U. ID No. 002, 003)

Diesel Engine Peaking Units 1 and 2, previously identified as Diesel Peaking Units 2 and 3, are diesel fired internal combustion engines which each drives a generator capable of producing electric power at a maximum rating of 2.5 megawatts. These units are each fired on No. 2 fuel oil, with a maximum sulfur content of 0.5 percent by weight, at a maximum firing rate of 201.6 gallons per hour. This corresponds to a maximum heat input of 28 MMBtu/hr. Diesel Engine Peaking Units 1 and 2 began commercial operation in 1970. The emission units are regulated under Rule 62-210.300, F.A.C., Permits Required.

Diesel Engine Peaking Units 1 and 2 have federally enforceable limits for visible emissions, and "not federally enforceable limits" for sulfur dioxide emissions, based on sulfur content of the fuel oil. Regardless, these units do not use control devises to meet these limits or standards, and therefore the requirements of CAM are not applicable.

Gas Turbine Peaking Unit 1 (E.U. ID No. 004)

The Gas Turbine Peaking Unit 1 consists of a gas turbine which drives a generator producing electric power at a nominal nameplate rating of 20 megawatts. The gas turbine is fired with natural gas, or No. 2 fuel oil with a maximum sulfur content of 0.5 percent by weight. The maximum fuel firing rate is 320 million cubic feet per hour of natural gas (approximately 330 MMBtu/hr) or 2,310 gallons per hour of No. 2 fuel oil (approximately 320 MMBtu/hr). Gas Turbine Peaking Unit 1 began commercial service in 1973. This emission unit is regulated under Rule 62-210.300, F.A.C., Permits Required. This unit is not subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines.

Gas Turbine Peaking Unit 1 has federally enforceable limits for visible emissions, and "not federally enforceable" limits for sulfur dioxide emissions, based on sulfur content of the fuel oil. Regardless, this unit does not use control devises to meet these limits or standards, and therefore the requirements of CAM are not applicable.

McIntosh Unit 2 (E.U. ID No. 005)

McIntosh Unit 2 is a nominal 114.7 megawatt (electric) fossil fuel fired steam generator. The unit is fired on low sulfur No. 6 or No. 2 fuel oil with a maximum heat input of 1,115 MMBtu/hr, or natural gas with a maximum heat input of 1,184.5 MMBtu/hr. McIntosh Unit 2 began commercial service in June, 1976. The emissions unit is regulated under Acid Rain, Phase II; and NSPS - 40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.

Although Unit 2 has federally enforceable limits for particulate matter, visible emissions, nitrogen oxides, and sulfur dioxide emissions, Unit 2 does not use control devises to meet these limits or standards. Therefore the requirements of CAM are not applicable to Unit 2.

McIntosh Unit 3 (E.U. ID No. 006)

McIntosh Unit 3 is a nominal 364 megawatt (electric) dry bottom wall-fired fossil fuel fired steam generator. The unit is fired on coal, residual oil, natural gas and co-fires derived fuel (RDF) and petroleum coke. The maximum heat input rate is 3,640 MMBtu/hr. Unit 3 is equipped with an electrostatic precipitator (ESP), and flue gas desulfurization system (FGD to control emissions. McIntosh Unit 3 began commercial service in September, 1982. The unit is regulated under Acid Rain, Phase II; and NSPS - 40 CFR 60, Subpart D, Standards of Performance for Fossil-Fuel Fired Steam Generators for Which Construction is Commenced After August 17, 1971, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C.; Rule 212.400(6), F.A.C., Prevention of Significant Deterioration (PSD); Rule 62-212.400(6), F.A.C., Best Available Control Technology (BACT) Determination.

Although Unit 3 has federally enforceable limit for nitrogen oxides, Unit 3 does not use a control devise to meet the limit. Therefore the requirements of CAM are not applicable to Unit 3 for NO_x.

Although there is a federally enforceable emission limit for SO_2, and a control device (FGD), CAM for SO_2 for Unit 3 is exempt pursuant to 40 CFR 64.2(b)(iii) Exemptions, Acid Rain Program. The requirements of Acid Rain Program to continuously monitor SO_2 emissions satisfy the requirements of CAM. Therefore Unit 3 is exempt from the requirements of the CAM Rule for SO_2 emissions.

Since a federally enforceable emission limit exists for PM, a control device is used to comply with the PM emission limit, and uncontrolled PM emissions are greater than 100 TPY, a CAM plan is required McIntosh Unit 3 for PM.

McIntosh Unit 5 (E.U. ID No. 028)

McIntosh Unit 5 is a 350 megawatt Westinghouse 501G combustion turbine and heat recovery steam generator operating in combined cycle mode. The turbine is fired with natural gas or a maximum 0.05 percent, by weight, sulfur content No. 2 or superior grade of distillate fuel oil. Emissions are initially controlled using Dry Low NOx combustion when firing natural gas; water injection when firing distillate fuel oil; use of inherently clean fuels; and, good combustion practices. Post combustion NOx emissions are controlled through the use of selective catalytic reduction (SCR) system. The emissions unit is regulated under Acid Rain, Phase II; NSPS -40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted and incorporated by reference in Rule 62-204.800(7), F.A.C., Best Available Control Technology (BACT) Determination, dated July 10, 1998. The combustion turbine began operation in March, 2000.

Although Unit 5 has federally enforceable limits for particulate matter, visible emissions, and sulfur dioxide emissions, Unit 5 does not use control devises to meet these limits or standards. Therefore the requirements of CAM are not applicable to Unit 5 for these pollutants.

Unit 5 is equipped with a SCR system for NO_x control. NO_x emissions are regulated under the previously mentioned NSPS -40 CFR 60, Subpart GG, F.A.C., and Best Available Control Technology (BACT) Determination, dated July 10, 1998, which requires continuous monitoring of NO_x emissions. Therefore Unit 5 is exempt from CAM requirements for NO_x pursuant to 40 CFR 64.2(b)(vi) which exempts units which have "emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in part 64.1."

II. PARTICULATE EMISSIONS FROM MCINTOSH UNIT 3

A. Emissions Unit Identification

McIntosh Unit 3 is a nominal 364 megawatt (electric) dry bottom wall-fired fossil fuel fired steam generator. The unit is fired on coal, residual oil, natural gas and co-fires derived fuel (RDF) and petroleum coke. The maximum heat input rate is 3,640 MMBtu/hr. Unit 3 is equipped with an electrostatic precipitator (ESP), and flue gas desulfurization system (FGD) to control emissions.

PM compliance testing is required annually on Unit 3. In addition, a continuous opacity monitoring system (COMS) is required to be used to record the opacity of the stack flue gas. The COMS must be properly calibrated, operated, and maintained in accordance with Rule 62-297.520, F.A.C.

C. Control Technology Description

PM emissions from Unit 3 are controlled by an electrostatic precipitator (ESP). The effectiveness of the ESP is evaluated with an annual stack test and continuous opacity measurements. A detailed description of the control equipment is included in the Title V renewal application.

D. Monitoring Approach

	Indicator No. 1
Indicator	Opacity via a COMS.
Measurement Approach	40 CFR 60, Appendix B, Performance Specification 1
Indicator Range	An excursion is defined as a VE (3-hour block averaging time) greater than the following: • 18.5 % for oil/RDF firing • 18.0 % for oil firing • 16.0 % for coal/pet. coke/RDF firing and coal/RDF firing • 15.0 % for coal firing and coal/pet. coke firing Excluding periods of startup, shutdown, and malfunction pursuant to Rule 62-210.700. An excursion will trigger an evaluation of operation of the power boiler and ESP. Corrective action will be taken as necessary. Any excursion will trigger recordkeeping and reporting requirements.
Data Representativeness	VE measurements are made in the stack.
Verification of Operational Status	NA
QA/QC Practices and Criteria	The COMS is automatically calibrated every 24 hours. Calibration information is recorded through a data acquisition system (DAS). A neutral density filter test is performed quarterly as well as preventative maintenance items; replace filters, clean optics, etc., as prescribed by the manufacturer.
Monitoring Frequency	Opacity is monitored continuously.
Data Collection Procedures	Six-minute averages are recorded through the DAS. Daily reports with all six-minute averages are generated.
Averaging Period	The averaging period for opacity observations is a six-minute block average.

E. Justification

1. Background

The pollutant specific emission unit is McIntosh Unit 3, which is fired on coal, residual oil, natural gas and co-fires derived fuel (RDF) and petroleum coke. It is controlled by an ESP, which has a control efficiency of approximately 94-percent.

2. Rationale for Selection of Performance Indicators

VE was selected as the performance indicator because it is indicative of good operation and maintenance of the ESP. When the ESP is operating properly, there will be very little VE from the ESP exhaust. An increase of VE beyond 15-percent opacity could indicate impaired performance of the particulate control device; therefore, VE is used as the performance indicator.

3. Rationale for Selection of Indicator Ranges

The selected indicator ranges are as follows:

- 18.5 % for oil/RDF firing
- 18.0 % for oil firing
- 16.0 % for coal/pet. coke/RDF firing and coal/RDF firing
- 15.0 % for coal firing and coal/pet. coke firing

These indicator ranges were selected because VE readings of greater magnitude could indicate impaired ESP performance and an associated increase in particulate emissions from the ESP outlet. To develop the indicator ranges, opacity readings were compared with stack test results of PM emissions. PM emissions (lb/MMBtu) were plotted versus the average of the opacity readings for three 1-hour stack tests. A linear curve was then applied to the data to develop relationship between opacity and PM (lb/MMBtu) emissions, see Figure 1. The resulting correlation was then utilized to estimate opacity readings equivalent to each fuel specific PM emission limitation. To account for error in the correlation, 10% was added to each indicator range.

Upon completion of each annual PM stack test, during which opacity is monitored, the correlation between opacity and PM emission will be updated. As a result, the indicator range for each fuel type will be updated to reflect the new correlation.

It should be noted that all of the indicator ranges are less than the permitted allowable opacity of 20% (6-minute average). When an excursion occurs, corrective action will be initiated, beginning with an evaluation of the occurrence, to determine the action required (if any) to correct the situation. All excursions will be documented and reported.

Table 1. CAM Applicability Determination for Lakeland Electric, C.D. McIntosh, Jr. Power Plant

Emission Source	Title V EU ID	Control Equipment	Controlled Pollutants with Emission Limits	Uncontrolled Emission Rate (TPY)[a] PM/PM_{10}	CAM Plan Required? (Yes/No)	Pollutants Requiring CAM	Comments
McIntosh Unit 1	001	None	-	-	No	None	No add-on emission controls
Diesel Engine Peaking Unit 1	002	None	-	-	No	None	No add-on emission controls
Diesel Engine Peaking Unit 2	003	None	-	-	No	None	No add-on emission controls
Gas Turbine Peaking Unit 1	004	None	-	-	No	None	No add-on emission controls
McIntosh Unit 2	005	None	-	-	No	None	No add-on emission controls
McIntosh Unit 3	006	ESP, FGD	PM, SO2	70,833	Yes	PM	SO2 subject to Acid Rain, Exempt from CAM.
McIntosh Unit 5	028	SCR	NOx	-	No	None	NOx subject to NSPS, exempt from CAM.

[a] Based on 3,640 MMBtu/hr, 8,760 hrs per year of coal firing, AP-42 Emission factor of 10(% Ash) lb PM/ton,

Firing Rate	3640	MMBtu/hr
Coal Heat Content	10500	Btu/lb
Coal Firing Rate	346666.7	lb/hr
	173.3333	Ton/hr
Ash content	9.33	%

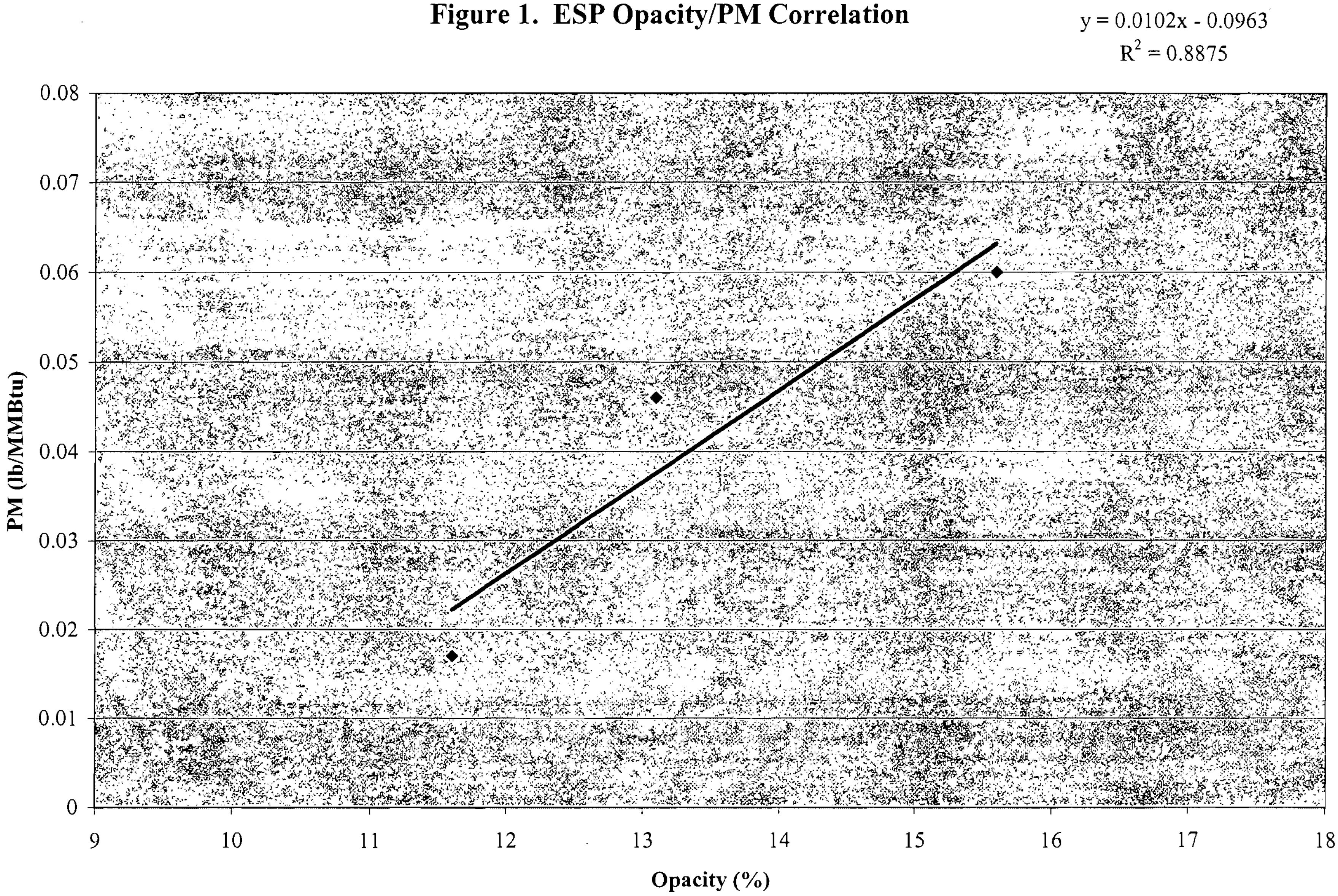


Figure 1. ESP Opacity/PM Correlation

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):

Diesel Peaking Units 1 and 2, previously identified as Diesel Peaking Units 2 and 3.

4. Emissions Unit Identification Number:
ID: **002, 003**
[ ] No ID
[ ] ID Unknown

5. Emissions Unit Status Code: **A**	6. Initial Startup Date: **1 Jan 1970**	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [ ]

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

Each diesel electric generating unit rated at 2.5-MW fired with diesel (No. 2 distillate) fuel only. These units are identical.

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:	**5**	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:		**28**	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 per diesel peaking unit.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

<u>List of Applicable Regulations</u>

See Attachment MC-FI-C12	

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? **S004, S005**

2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

Each emission unit (diesel) has a separate stack.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common:
S004 = Diesel Unit 2
S005 = Diesel Unit 3

5. Discharge Type Code: **V**

6. Stack Height: **20** feet

7. Exit Diameter: **2.6** feet

8. Exit Temperature: **715** °F

9. Actual Volumetric Flow Rate: **24,529** acfm

10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm

12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:
Zone: **17** East (km): **409.1** North (km): **3106.3**

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

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

Segment Description and Rate: Segment 1 of 1

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

Diesel Oil

2. Source Classification Code (SCC): **2-01-001-02**	3. SCC Units: **1,000 gallons**	
4. Maximum Hourly Rate: **0.2**	5. Maximum Annual Rate: **1,766**	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: **0.5**	8. Maximum % Ash:	9. Million Btu per SCC Unit: **138**

10. Segment Comment (limit to 200 characters):

Maximum hourly rate: 0.2016 maximum hourly and annual rate based on operating permit limits for each diesel unit; based on 19,500 Btu/lb; 7.1 lb/gal diesel fuel.

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:
14. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:

10. Segment Comment (limit to 200 characters):

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

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

Emissions Unit Information Section 4 **of** 8 **Diesel Engine Peaking Units 1 & 2**

Pollutant Detail Information Page 1 **of** 1 **Sulfur Dioxide**

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: **15.4** lb/hour **67.5** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.5% Sulfur Fuel Oil** Reference: **Permit 1050004-011-AV**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **Permit 1050004-011-AV**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Potential emissions provided for each unit.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.5% Sulfur Oil**	4. Equivalent Allowable Emissions: **15.4** lb/hour **67.5** tons/year
5. Method of Compliance (limit to 60 characters): **Fuel Analysis (vendor or inhouse)**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Permit 1050004-011-AV**	

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: **20** % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:

Annual VE Test EPA Method 9 if >400 hr

5. Visible Emissions Comment (limit to 200 characters):

FDEP Rule 62-296.320(4)(b)1.

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

Continuous Monitoring System: Continuous Monitor ______ of ______

1. Parameter Code:	2. Pollutant(s):

3. CMS Requirement: [ ] Rule [ ] Other

4. Monitor Information:
Manufacturer:
Model Number: Serial Number:

5. Installation Date:	6. Performance Specification Test Date:

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

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: % Exceptional Conditions: **100** %
Maximum Period of Excess Opacity Allowed: **60** min/hour

4. Method of Compliance:

None

5. Visible Emissions Comment (limit to 200 characters):

FDEP Rule 62-210.700(1) allows up to 100% for 2 hr (120 minutes) per 24-hr period for start up, shutdown or malfunction.

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

Continuous Monitoring System: Continuous Monitor ______ of ______

1. Parameter Code:	2. Pollutant(s):

3. CMS Requirement: [ ] Rule [ ] Other

4. Monitor Information:
Manufacturer:
Model Number: Serial Number:

5. Installation Date:	6. Performance Specification Test Date:

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

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

Supplemental Requirements

1. Process Flow Diagram
   [X] Attached, Document ID: MC-EU4-J1 [ ] Not Applicable [ ] Waiver Requested

2. Fuel Analysis or Specification
   [X] Attached, Document ID: MC-EU4-J2 [ ] Not Applicable [ ] Waiver Requested

3. Detailed Description of Control Equipment
   [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested

4. Description of Stack Sampling Facilities
   [ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested

5. Compliance Test Report

   [X] Attached, Document ID: MC-EU4-J5

   [ ] Previously submitted, Date: ____________

   [ ] Not Applicable

6. Procedures for Startup and Shutdown
   [X] Attached, Document ID: MC-EU4-J6[ ] 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: MC-EU4-J11 [ ] Not Applicable

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

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

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

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

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

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

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

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

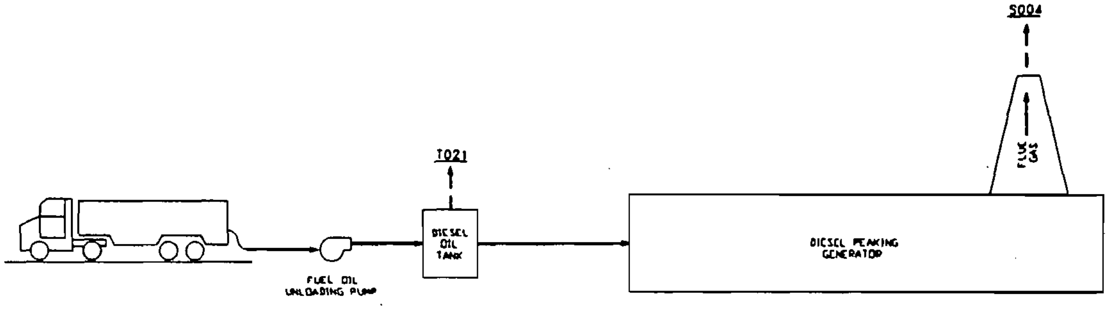
[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
Attached, Document ID:________

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

[X] Not Applicable

ATTACHMENT MC-EU4-J1

PROCESS FLOW DIAGRAM



REV. NO.	BY	DATE	APPR.	REVISION
3	MG	5-29-96	HP	ISSUED FOR TITLE V
2	MG	5-15-96	HP	CHANGE TITLE
1	MG	8-9-95		DELETED T116

LAKELAND
ELECTRIC
& WATER

DESCRIPTION

LAKELAND ELECTRIC & WATER UTILITIES
C.D. McINTOSH POWER PLANT
DIESEL PEAKER NO. 2
(DIESEL NO. 1)
PROCESS FLOW DIAGRAM

DIVISION PRODUCTION ENGINEERING
ENGINEER PATTERSON
DRN. BY: MGIEGER DATE 9-19-94
APPR. BY: DATE

CAD SCALE NONE
PROJ. NO. AIR PERMIT
DWG. NO. LMC-EU4-L1/SKM-28 REV. 3

SIZE B

ATTACHMENT MC-EU4-J2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT MC-EU4-J2

FUEL ANALYSIS
NO. 2 FUEL OIL

Parameter	Typical Value	Max Value
API gravity @ 60 F	30[1]	-
Relative density	6.92 lb/gal [2]	
Heat content	18,400 Btu / lb (LHV)	
% sulfur	<0.5 [2]	0.5 [3]
% nitrogen	0.025 - 0.030	
% ash	negligible	0.01 [1]

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit 1050004-011-AV.

ATTACHMENT MC-EU4-J5

COMPLIANCE TEST REPORTS
VISIBLE EMISSIONS

VISIBLE EMISSION OBSERVATION FORM

METHOD USED (CIRCLE ONE)
[✓ Method 9] 203A 203B Other:

PAGE 1 **OF** 1

COMPANY NAME City of Lakeland

STREET ADDRESS McIntosh Power Plant
3030 East Lake Parker Drive

CITY Lakeland **STATE** FL **ZIP** 33805

PHONE (KEY CONTACT) 863-834-6600 **SOURCE ID NUMBER**

PROCESS EQUIPMENT Diesel Peaking Unit (#1) **OPERATING MODE** 2.4 MW

CONTROL EQUIPMENT None **OPERATING MODE** N.A.

DESCRIBE EMISSION POINT Stack Exit

HEIGHT ABOVE GROUND LEVEL Start ~ 20' End ~ 20'

HEIGHT RELATIVE TO OBSERVER Start ~ 20' End ~ 20'

DISTANCE FROM OBSERVER Start ~ 70' End ~ 70'

DIRECTION FROM OBSERVER Start NE End NE

DESCRIBE EMISSIONS Start Smoke & Heat Waves End Smoke & Heat Waves

EMISSION COLOR Start Black End Black

WATER DROPLET PLUME ☐ Attached ☐ Detached ☒ None

POINT IN THE PLUME AT WHICH OPACITY WAS DETERMINED Start Exit of Stack End Exit of Stack

DESCRIBE PLUME BACKGROUND Start Sky & Elec. Wires End Sky & Elec. Wires

BACKGROUND COLOR Start Bl/Wht/Gy End Bl/Wt/Grey

SKY Sunny: Start 60%clouds End 65%clouds

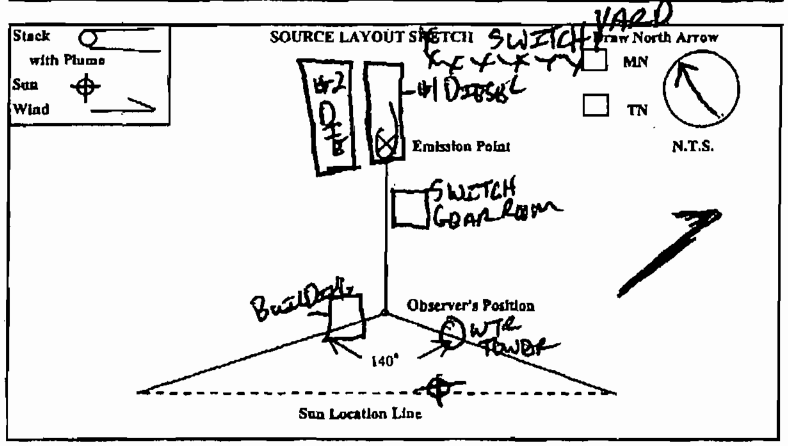
WIND SPEED Start ~ 3.0 mph End ~10.1 mph

WIND DIRECTION Start SW End SW

AMBIENT TEMP Start 88°F End 88°F

WET BULB TEMP 69°F / 71°F

RH percent 51% / 49%



ADDITIONAL INFORMATION (incl. INCLINE DEG., SET AVG., FUEL USED, etc.)
Incline = 14.5°
40 CFR 60, App. A, Method 9, 2.5 Set Avg. = 14.79%
Fuel used during test = ~ 90 gals.

OBSERVATION DATE 4-Apr-03 **START TIME** 1437 **END TIME** 1507

MIN \ SEC	0	15	30	45	COMMENTS
1	10	10	10	10	
2	10	10	5	10	
3	10	10	5	10	
4	10	10	10	10	
5	10	10	10	10	
6	10	10	10	10	
7	10	10	15	10	
8	10	15	10	10	
9	10	10	10	10	
10	10	10	10	10	
11	10	10	10	10	
12	10	10	15	15	
13	15	10	10	10	
14	15	15	10	15	
15	15	15	10	15	
16	10	10	15	10	
17	15	15	10	10	
18	15	15	15	15	
19	10	15	15	15	
20	15	15	15	15	
21	15	15	10	15	
22	15	15	15	10	
23	15	15	15	15	
24	15	15	15	10	
25	15	15	15	15	
26	15	15	15	15	
27	15	15	15	15	
28	15	15	15	10	
29	15	15	15	15	
30	15	15	15	15	

OBSERVER'S NAME (PRINT) James Bibby

OBSERVER'S SIGNATURE **DATE** 4-Apr-03

ORGANIZATION City of Lakeland

CERTIFIED BY Dept. of Env. Reg.thru EASTERN TECH. ASSC. **EXP. DATE** 14-Aug-03

VISIBLE EMISSION OBSERVATION FORM

RECEIVED
Environmental Affairs
APR 7 2003

METHOD USED (CIRCLE ONE)	[✓ Method 9] 203A 203B Other:__________
PAGE	1
OF	1

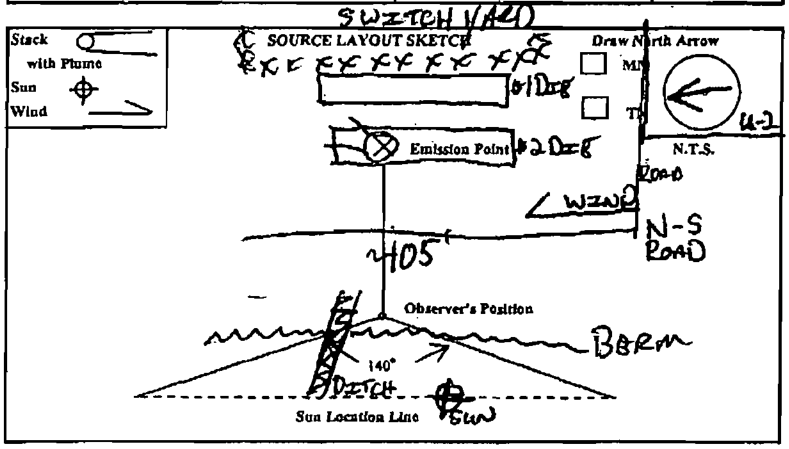
COMPANY NAME City of Lakeland		
STREET ADDRESS McIntosh Power Plant 3030 East Lake Parker Drive		
CITY Lakeland	STATE FL	ZIP 33805
PHONE (KEY CONTACT) 863-834-6600	SOURCE ID NUMBER 003	

PROCESS EQUIPMENT Diesel Peaking Unit (#2)	OPERATING MODE 2.5 MW
CONTROL EQUIPMENT None	OPERATING MODE N.A.

DESCRIBE EMISSION POINT Stack Exit	
HEIGHT ABOVE GROUND LEVEL Start ~ 20' End ~ 20'	HEIGHT RELATIVE TO OBSERVER Start ~ 20' End ~ 20'
DISTANCE FROM OBSERVER Start ~ 105' End ~ 105'	DIRECTION FROM OBSERVER Start NNE End NNE

DESCRIBE EMISSIONS Start Smoke & Heat Waves	End Smoke & Heat Waves
EMISSION COLOR Start Black End Black	WATER DROPLET PLUME ☐ Attached ☐ Detached ☒ None
POINT IN THE PLUME AT WHICH OPACITY WAS DETERMINED Start Exit of Stack	End Exit of Stack

DESCRIBE PLUME BACKGROUND Start Sky & Elec. Wires	End Sky & Elec. Wires	
BACKGROUND COLOR Start Blue/White End Bl/Wt/Grey	SKY Start Black End Black	
WIND SPEED Start ~ 11.1 mph End ~ 8.7 mph	WIND DIRECTION Start Black End Black	
AMBIENT TEMP Start 84°F End 85°F	WET BULB TEMP 66°F / 64°F	RH percent 47% / 48%



ADDITIONAL INFORMATION (incl. INCLINE DEG., SET AVG., FUEL USED, etc.)
Incline = 10.3°
40 CFR 60, App. A, Method 9, 2.5 Set Avg. = 11.67%
Fuel used during test = ~ 92 gals.

OBSERVATION DATE	START TIME	END TIME
3-Apr-03	1502	1532

MIN \ SEC	0	15	30	45	COMMENTS
1	10	10	10	15	
2	10	10	10	5	
3	10	5	10	10	
4	5	10	10	10	
5	10	10	10	10	
6	10	5	10	10	
7	10	10	5	10	
8	10	10	15	10	
9	10	10	10	5	
10	10	10	10	10	
11	5	10	10	10	
12	10	10	10	10	
13	10	10	10	5	
14	5	10	5	10	
15	10	10	10	10	
16	5	5	10	10	
17	10	5	5	10	
18	10	10	10	10	
19	10	10	10	10	
20	10	10	10	10	
21	15	10	10	10	
22	15	10	10	10	
23	10	10	15	10	
24	15	10	15	15	
25	10	10	15	10	
26	10	15	10	10	
27	10	10	10	10	
28	10	10	15	10	
29	10	15	10	10	
30	10	10	10	15	

OBSERVER'S NAME (PRINT) James Bibby	
OBSERVER'S SIGNATURE James Bibby	DATE 3-Apr-03
ORGANIZATION City of Lakeland	
CERTIFIED BY Dept. of Env. Reg.thru EASTERN TECH. ASSC.	EXP. DATE 14-Aug-03

ATTACHMENT MC-EU4-J6

PROCEDURES FOR STARUP AND SHUTDOWN

ATTACHMENT MC-EU4-J6

PROCEDURES FOR STARTUP/SHUTDOWN

Startup and shutdown for these units are fully automatic.

Startup for the diesel units begin at low loads using distillate oil (i.e., diesel).

Corrective actions may include switching the unit from automatic (remote) to local control, or changing load conditions. Best Operating Practices based on manufacturer recommendations are adhered to and all efforts to minimize both the level and duration of excess emissions are undertaken.

Shutdown is performed by reducing the unit load (electrical production) to a minimum level, opening the breaker (which disconnects the unit from the system electrical grid), shutting off the fuel and coasting down to stop.

ATTACHMENT MC-EU4-J11

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT MC-EU4-J11
ALTERNATIVE METHODS OF OPERATION

The diesel unit can operate from 0 to 100 percent load on diesel/distillate fuel oil with no limitation on the hours of operation.

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):

Gas Turbine Peaking Unit 1

4. Emissions Unit Identification Number: [ ] No ID
ID: **004** [ ] ID Unknown

5. Emissions Unit Status Code: **A**	6. Initial Startup Date: **1 Jan 1973**	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [ ]

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

Fired with diesel (No. 2) fuel and natural gas.

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:	**20**	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:		**330**	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):			

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment MC-FI-C12	

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? **S006**

2. Emission Point Type Code: **1**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

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

5. Discharge Type Code: **V**

6. Stack Height: **35** feet

7. Exit Diameter: **13.5** feet

8. Exit Temperature: **900** °F

9. Actual Volumetric Flow Rate: **682,334** acfm

10. Water Vapor: %

11. Maximum Dry Standard Flow Rate: dscfm

12. Nonstack Emission Point Height: feet

13. Emission Point UTM Coordinates:

Zone: **17** East (km): **409.2** North (km): **3106.4**

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

Exit diameter based on equivalent diameter based on stack area.
Stack dimensions: rectangular 13'2" x 10'11".
Volumetric flow for distillate oil: natural gas = 742,174 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: **2.31**

5. Maximum Annual Rate: **20,236**

6. Estimated Annual Activity Factor:

7. Maximum % Sulfur: **0.5**

8. Maximum % Ash:

9. Million Btu per SCC Unit: **138**

10. Segment Comment (limit to 200 characters):

mmBtu/SCC based on 19,500 Btu/lb, 7.1 lb/gal diesel fuel.

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):

3. SCC Units: **Million Cubic Feet**

4. Maximum Hourly Rate: **0.32**

5. Maximum Annual Rate: **2,803**

6. Estimated Annual Activity Factor:

15. Maximum % Sulfur:

8. Maximum % Ash:

9. Million Btu per SCC Unit: **1,024**

10. Segment Comment (limit to 200 characters):

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

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

Emissions Unit Information Section 5 of 8 **Gas Turbine Peaking Unit 1**

Pollutant Detail Information Page 1 of 1 **Sulfur Dioxide**

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: **164** lb/hour **718.4** tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: **0.5% Sulfur Fuel** Reference: **Permit 1050004-011-AV**	7. Emissions Method Code: **0**
8. Calculation of Emissions (limit to 600 characters): **2,320 gal/hr x 7.1 lb/gal x 0.005 lb S/lb fuel x 2 lb SO_2/lb S = 164 lb/hr**	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Emissions for distillate oil firing.**	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **0.5**	4. Equivalent Allowable Emissions: **164** lb/hour **718.4** tons/year
5. Method of Compliance (limit to 60 characters): **Vendor Fuel Analysis (vendor or inhouse).**	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): **Permit 1050004-011-AV**	

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: 20 % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:
Annual VE Test EPA Method 9 if >400 hr

5. Visible Emissions Comment (limit to 200 characters):
FDEP Rules 62-296.320(4)(b)1. and 62-297.310(7)(a)8.

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

Continuous Monitoring System: Continuous Monitor ______ of ______

1. Parameter Code:	2. Pollutant(s):

3. CMS Requirement: [ ] Rule [ ] Other

4. Monitor Information:
Manufacturer:
Model Number: Serial Number:

5. Installation Date:	6. Performance Specification Test Date:

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

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**	2. Basis for Allowable Opacity: [X] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: % Exceptional Conditions: **100** %
Maximum Period of Excess Opacity Allowed: **60** min/hour

4. Method of Compliance:
None

5. Visible Emissions Comment (limit to 200 characters):

FDEP Rule 62-210.700(1), start up, shutdown or malfunction.

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

Continuous Monitoring System: Continuous Monitor ______ of ______

1. Parameter Code:	2. Pollutant(s):

3. CMS Requirement: [ ] Rule [ ] Other

4. Monitor Information:
Manufacturer:
Model Number: Serial Number:

5. Installation Date:	6. Performance Specification Test Date:

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

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

Supplemental Requirements

1. Process Flow Diagram
   [X] Attached, Document ID: MC-EU5-J1 [ ] Not Applicable [ ] Waiver Requested
2. Fuel Analysis or Specification
   [X] Attached, Document ID: MC-EU5-J2 [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment
   [ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities
   [ ] Attached, Document ID: ______ [X] Not Applicable [ ] Waiver Requested
5. Compliance Test Report
   [X] Attached, Document ID: MC-EU5-J5
   [ ] Previously submitted, Date: ______
   [ ] Not Applicable
6. Procedures for Startup and Shutdown
   [X] Attached, Document ID: MC-EU5-J6[ ] 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: MC-EU5-J11 [ ] Not Applicable

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

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

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

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

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

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

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

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

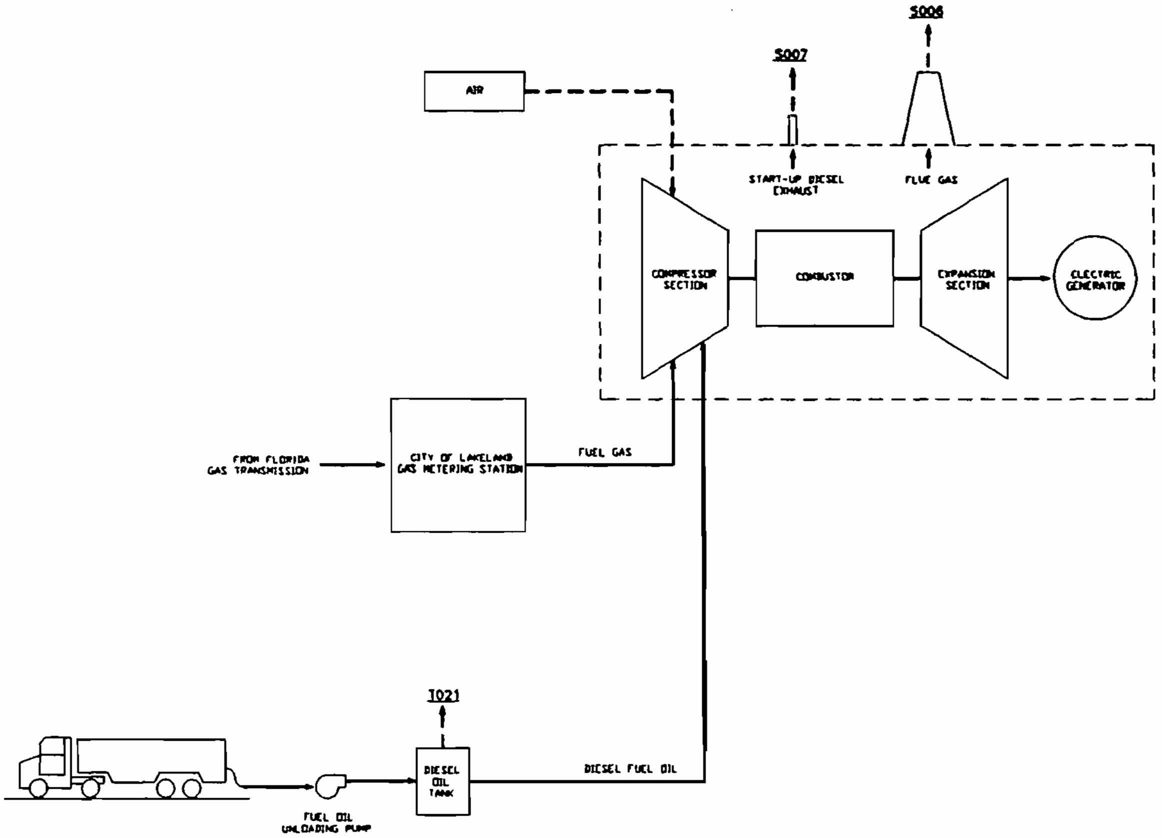
[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
Attached, Document ID: ________

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

[X] Not Applicable

ATTACHMENT MC-EU5-J1

PROCESS FLOW DIAGRAM



1	MG	8-9-95		DELETED T116
2	MG	5-15-96	HP	CHANGE TITLE
3	MC	5-29-98	HP	ISSUED FOR TITLE V
REV. NO.	BY	DATE	APPR.	REVISION

LAKELAND
ELECTRIC
& WATER

DESCRIPTION

LAKELAND ELECTRIC & WATER UTILITIES
C.D. McINTOSH POWER PLANT
GAS TURBINE PEAKER NO. 1
PROCESS FLOW DIAGRAM

DIVISION PRODUCTION ENGINEERING
ENGINEER PATTERSON
DRN. BY: MCIEGER
DATE 9-19-94
APPR. BY:

CAD
SCALE NONE
PROJ. NO. AIR PERMIT
DWG. NO. LMC-EU5-L1/SKM-30
REV. 3

SIZE B

ATTACHMENT MC-EU5-J2

FUEL ANALYSIS OR SPECIFICATION

ATTACHMENT MC-EU5-J2

FUEL ANALYSIS
NATURAL GAS ANALYSIS

Parameter	Typical Value	Max Value
Relative density	0.58 (compared to air)	
heat content	950 - 1124 Btu/cu ft. (hhv)	
% sulfur	0.43 grains/CCF [1]	1 grain/100 CF
% nitrogen	0.8% by volume	
% ash	negligible	

Note: The values listed are "typical" values based upon information supplied by Florida Gas Transmission (FGT). However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

---

[1] Data from laboratory analysis

ATTACHMENT MC-EU5-J2

FUEL ANALYSIS
NO. 2 FUEL OIL

Parameter	Typical Value	Max Value
API gravity @ 60 F	30[1]	-
Relative density	6.92 lb/gal [2]	
Heat content	18,400 Btu / lb (LHV)	
% sulfur	<0.5 [2]	0.5 [3]
% nitrogen	0.025 - 0.030	
% ash	negligible	0.01 [1]

Note: The values listed are "typical" values based upon 1) information gathered by laboratory analysis, and 2) fuel purchasing specifications. However, analytical results from grab samples of fuel taken at any given point in time may vary from those listed.

[1] Data taken from the fuel procurement specification

[2] Data from laboratory analysis

[3] Data from current air permit (AO53-244727) not an applicable requirement under 62-210.200.

ATTACHMENT MC-EU5-J5

COMPLIANCE TEST REPORTS
VISIBLE EMISSIONS

ATTACHMENT MC-EU5-J5

COMPLIANCE TEST REPORTS
VISIBLE EMISSIONS

Visible emission test report for the Gas Turbine Peating Unit 1, emission unit 005, will be submitted at a later date, due to mechanical failure.

ATTACHMENT MC-EU5-J6

PROCEDURES FOR STARUP AND SHUTDOWN

ATTACHMENT MC-EU5-J6

PROCEDURES FOR STARTUP/SHUTDOWN

Startup for the gas turbine begins with an electric control system using a switch to initiate the unit startup cycle. The unit generator is synchronized with the grid and can be "on line" (electrical power production) within 5 minutes from startup.

The gas turbine has no emission controls. If excess emissions are encountered during startup or shutdown, the nature and cause of any malfunction is identified, along with the corrective action taken or preventative measures adopted. Corrective actions may include switching the unit from automatic (remote) to local control. Best Operating Practices are adhered to and all efforts to minimize both the level and duration of excess emissions are undertaken.

Shutdown is performed by reducing the unit load (electrical production) to a minimum level, opening the breaker (which disconnects the unit generator from the system electrical grid), shutting off the fuel, and coasting to a stop.

ATTACHMENT MC-EU5-J11

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT MC-EU5-J11

ALTERNATIVE METHODS OF OPERATION

GAS TURBINE UNIT 1

The gas turbine can operate on both natural gas and fuel oil (No. 2 fuel). The maximum sulfur content in the fuel oil will not exceed 0.5 percent. This unit can operate from 0 to 100 percent load for the entire year (i.e., 8,760 hours) and can fire either fuel oil or natural gas fire with no restrictions on hours of operation.

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 – Combined Cycle Configuration

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

5. Emissions Unit Status Code: **A**	6. Initial Startup Date: **Jan 2002**	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [X]

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

This emission unit is a Westinghouse 501G combustion turbine currently operating in combined cycle with a HRSG and 120 MW steam electric turbine. The unit will be fired primarily with natural gas and distillate fuel oil as backup fuel. The diesel fuel may contain the additive Soltron as recommended by the manufacturer.

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 – Oil Firing

Selective Catalytic Reduction – Natural Gas Firing

Oxidation Catalyst (Attachment MC-EU6-J3)

2. Control Device or Method Code(s): **25, 28, 65, 39**

Emissions Unit Details

1. Package Unit:
   Manufacturer: **Westinghouse** Model Number: **501G**
2. Generator Nameplate Rating: **369** 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: **2,407** 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 for natural gas firing (LHV) at baseload; ISO conditions; maximum for oil firing (LHV) is 2,236 mmBtu/hr at baseload; ISO conditions. Heat input is a function of compressor inlet temperature.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment MC-FI-C12	

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: **300** feet	7. Exit Diameter: **20** feet
8. Exit Temperature: **187** °F	9. Actual Volumetric Flow Rate: **1,271,428** acfm	10. Water Vapor: **12.44** %

11. Maximum Dry Standard Flow Rate: 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 turbine inlet operating condition firing natural gas at baseload; for oil 188°F, 1,291,502 ACFM and 12.05% water vapor at baseload; ISO conditions.

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: **17.0**
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 = 2,236 mmBtu/hr / 131.5 mmBtu/ 1,000 gal / 1,000 gal; Annual permit limited to 559 x 10^9 Btu (LHV) per year. Max hourly; function of turbine inlet temp. The diesel fuel may contain the additive Soltron as recommended by the manufacturer. See MSDS for Soltron.

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: **2.53**
5. Maximum Annual Rate: **16,462**
6. Estimated Annual Activity Factor:
16. Maximum % Sulfur:
8. Maximum % Ash:
9. Million Btu per SCC Unit: **950**
10. Segment Comment (limit to 200 characters):

Max. based on 59°F; 950 Btu/CF LHV. Annual permit limited to 15.639 x 10^{12} Btu (LHV) per year. Max. hourly a function of turbine inlet temperature.
See Permit No. PSD-FL-245 (1050004-004-AC) Condition III.13.

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM			NS
SO_2			EL
NO_X	25, 28	65	EL
CO	39(Pending)		NS
VOC	39(Pending)		NS
PM_{10}			NS

Emissions Unit Information Section 6 of 8 **Unit 5**

Pollutant Detail Information Page 1 of 6 **Particulate Matter - Total**

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; Siemens Westinghouse**

7. Emissions Method Code: **2**

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

(8,510 hr gas x 8.8 lb/hr + 250 hr oil x 92.8 lb/hr)/2,000 lb/ton = 49.0 TPY

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

Lb/hr based on oil firing, 50% load, 30°F; Tons/yr based on 8,510 hr/yr gas firing and 250 hr/yr oil firing; 59°F conditions, baseload.

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):

PSD-FL-245 (1050004-004-AC)

Oil firing; annual based on 250 hr/yr at ISO conditions.

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

Potential/Fugitive Emissions

1. Pollutant Emitted:	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): **PSD-FL-245 (1050004-004-AC)** **Gas firing - 30°F, 100% load; annual based on 59°F; 100% load, 8,760 hr/yr.**	

Emissions Unit Information Section 6 of 8 **Unit 5**

Pollutant Detail Information Page 2 of 6 **Sulfur Dioxide**

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 **38.4** 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):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): **Lb/hr and TPY based on PSD-FL-245 (1050004-004-AC).**	

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): **PSD-FL-245 (1050004-004-AC)** **Oil firing.**	

Emissions Unit Information Section 6 **of** 8 **Unit 5**

Pollutant Detail Information Page 2 **of** 6 **Sulfur Dioxide**

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

Potential/Fugitive Emissions

1. Pollutant Emitted:

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:
8 lb/hr

4. Equivalent Allowable Emissions:
8 lb/hour **35.0** tons/year

5. Method of Compliance (limit to 60 characters):

Fuel Sampling

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

PSD-FL-245 (1050004-004-AC)

Gas firing.

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: **148** lb/hour **321** 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):

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

Lb/hr based on oil firing baseload; Tons/yr based on 8,510 hr/yr gas firing and 250 hr/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: **15 ppmvd@15% O_2**

4. Equivalent Allowable Emissions: **148** lb/hour **18.5** tons/year

5. Method of Compliance (limit to 60 characters):

3-Hr Average (corrected to 15% Oxygen)

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

PSD-FL-245 (1050004-004-AC)

Oil firing baseload; annual based on 250 hr/yr. 200 lb/hr 24-hr Block Average, authorized for Startup, Shutdown or fuel change if Fuel oil is fired.

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

Potential/Fugitive Emissions

1. Pollutant Emitted:
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:
   7.5 ppmvd@15% O_2
4. Equivalent Allowable Emissions:
   71.1 lb/hour **311.4** tons/year
5. Method of Compliance (limit to 60 characters):
   CEM 3-Hr Average and Annual RATA EPA Method 7E
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):
   PSD-FL-245 (1050004-004-AC)
   Gas firing; annual based on 8,760 hr/yr. 100 lb/hr, 24-hr Block Average, authorized for Startup, Shutdown when firing natural gas.

Emissions Unit Information Section 6 of 8 Unit 5

Pollutant Detail Information Page 4 of 6 Carbon Monoxide

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: **38.6** lb/hour **41** 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):

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

Lb/hr based on oil firing; Tons/yr based on 8,510 hr/yr gas firing and 250 hr/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:
Oxidation Catalyst (8/1/03)

4. Equivalent Allowable Emissions:
38.6 lb/hour **4.8** tons/year

5. Method of Compliance (limit to 60 characters):

None

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

PSD-FL-245 (1050004-004-AC) Oil firing, annual based on 250 hr/yr.
90% reduction @ base load, oxidation catalyst. See Attachment MC-FI-C12.

Emissions Unit Information Section 6 of 8 **Unit 5**

Pollutant Detail Information Page 4 of 6 **Carbon Monoxide**

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

Potential/Fugitive Emissions

1. Pollutant Emitted:

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:
Oxidation Catalyst (8/1/03)

4. Equivalent Allowable Emissions:
8.5 lb/hour **37.2** tons/year

5. Method of Compliance (limit to 60 characters):

Annual test for 2 ppmvd criteria.

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

PSD-FL-245 (1050004-004-AC), Gas firing,; annual based on 8,760 hr/yr.
90% reduction @ base load, oxidation catalyst. See Attachment MC-FI-C12.

Emissions Unit Information Section 6 of 8 **Unit 5**

Pollutant Detail Information Page 5 of 6 **Volatile Organic Compounds**

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: **NA** lb/hour **NA** 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):	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):	

Allowable Emissions Allowable Emissions 1 of 1

1. Basis for Allowable Emissions Code: **OTHER**	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: **Oxidation Catalyst (8/1/03)**	4. Equivalent Allowable Emissions: **NA** lb/hour **NA** 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): **PSD-FL-245 (1050004-004-AC). Gas and oil firing. Oxidation Catalyst, CO emissions shall be employed as a surrogate for VOC emissions and no further annual testing will be required. See Attachment MC-FI-C12.**	

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; Siemens Westinghouse**

7. Emissions Method Code: **2**

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

(8,510 hr gas x 8.8 lb/hr + 250 hr oil x 92.8 lb/hr) / 2,000 lb/ton = 49.0 TPY.

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

Lb/hr based on oil firing, 50% load, 30°F; TPY based on 8,510 hr/yr gas firing and 250 hr/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):

PSD-FL-245 (1050004-004-AC)

Oil firing; annual based on 250 hr/yr at ISO conditions.

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

Potential/Fugitive Emissions

1. Pollutant Emitted:	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): **PSD-FL-245 (1050004-004-AC)** **Gas firing - 30°F, 100% load; annual based on 59°F; 100% load, 8,760 hr/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: **Siemens**
Model Number: **300-CLD** Serial Number: **28J04015**

5. Installation Date:
Relocation to new stack December 2001

6. Performance Specification Test Date:
February 27, 2002

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

NO_X CEM proposed to meet requirements of 40 CFR Part 75.

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

Visible Emissions Limitation: Visible Emissions Limitation 2 of 2

1. Visible Emissions Subtype: **VE99**

2. Basis for Allowable Opacity: [X] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: % Exceptional Conditions: **100** %
Maximum Period of Excess Opacity Allowed: **6** min/hour

4. Method of Compliance:

None

5. Visible Emissions Comment (limit to 200 characters):

FDEP Rule 62-210.700(1), which allows 2 hr (120 minutes) per 24 hr for start up, shutdown and malfunction. See Attachment MC-EU1-J6.

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: **Siemens**
Model Number: **Oxymat 6E** Serial Number: **N1K80365**

5. Installation Date:
December 2001

6. Performance Specification Test Date:
February 27, 2002

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

Monitor is an O$_2$ analyzer for NO$_x$ emissions determination.

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

Supplemental Requirements

1. Process Flow Diagram
[X] Attached, Document ID: MC-EU6-J1 [ ] Not Applicable [ ] Waiver Requested

2. Fuel Analysis or Specification
[X] Attached, Document ID: MC-EU6-J2 [ ] Not Applicable [ ] Waiver Requested

3. Detailed Description of Control Equipment
[X] Attached, Document ID: MC-EU6-J3 [ ] Not Applicable [ ] Waiver Requested

4. Description of Stack Sampling Facilities
[X] Attached, Document ID: MC-EU6-J4 [ ] Not Applicable [ ] Waiver Requested

5. Compliance Test Report

[X] Attached, Document ID: MC-EU6-J5

[ ] Previously submitted, Date: ______________

[ ] Not Applicable

6. Procedures for Startup and Shutdown
[ ] Attached, Document ID: __________ [X] Not Applicable [ ] Waiver Requested

7. Operation and Maintenance Plan
[ ] Attached, Document ID: __________ [X] Not Applicable [ ] Waiver Requested

8. Supplemental Information for Construction Permit Application
[ ] Attached, Document ID: ______________ [X] Not Applicable

9. Other Information Required by Rule or Statute
[ ] Attached, Document ID: _______ [X] Not Applicable

10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

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

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

13. Identification of Additional Applicable Requirements
[X] Attached, Document ID: MC-FI-C12 [ ] Not Applicable

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

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

[X] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
Attached, Document ID: MC-EU1-J15

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

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

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

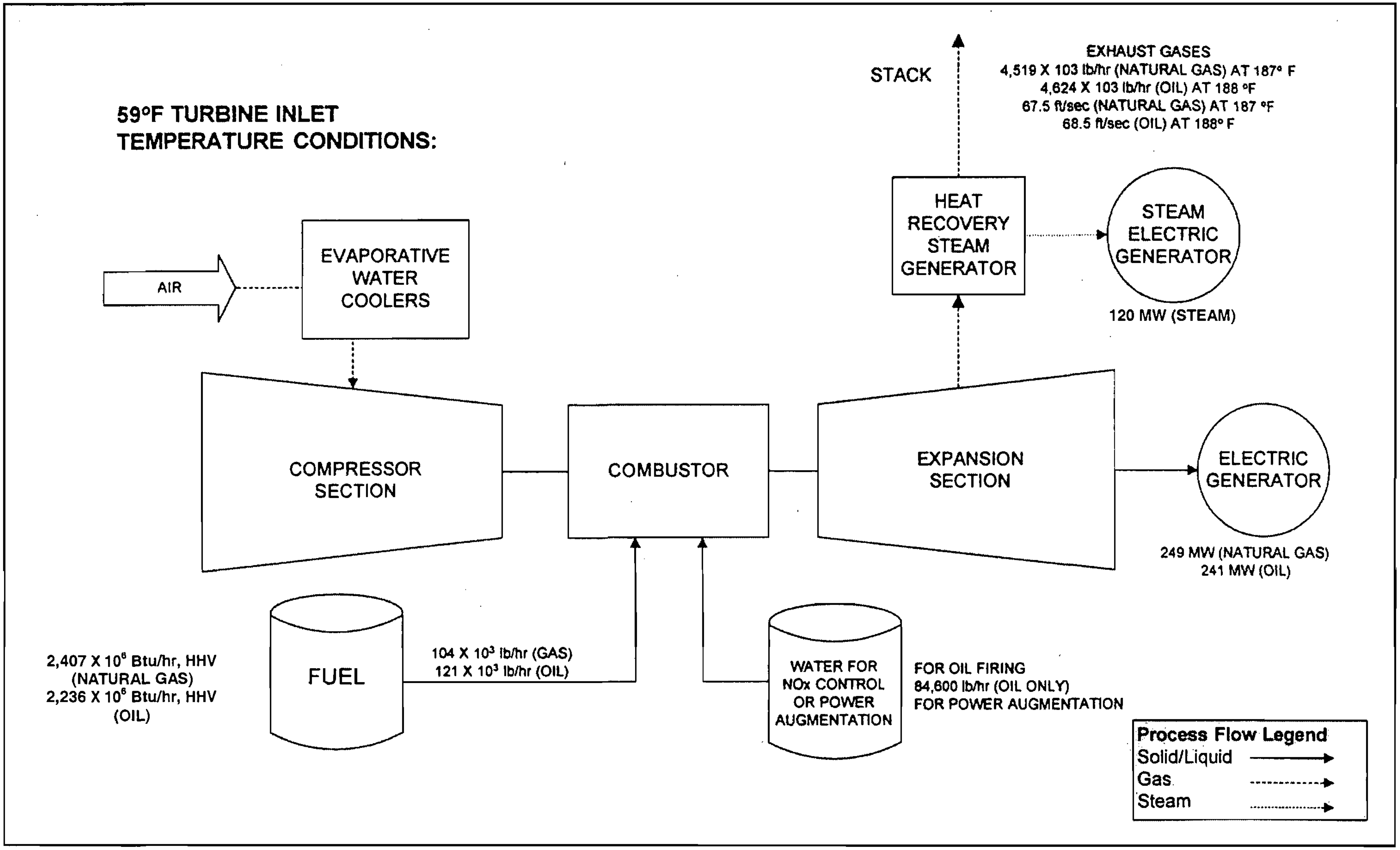
[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
Attached, Document ID:________

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

[ ] Not Applicable

ATTACHMENT MC-EU6-J1

PROCESS FLOW DIAGRAM



Golder Associates

ATTACHMENT MC-EU6-J2

FUEL ANALYSIS OR SPECIFICATION

BEST AVAILABLE COPY

September 24, 1999

CITY OF LAKELAND
3030 E. Lake Parker Dr.
Lakeland, FL 33805
Attn: Steven Parrish

Sample identification by
City of Lakeland

Kind of sample
reported to us #5 Diesel

Sample ID: 570-99

Sample taken at Unit #5 Diesel Tank

Sample taken by City of Lakeland

Date sampled September 20, 1999

Date received September 21, 1999

Analysis Report No. 71-102976 Page 2 of 2

DISTILLATION

% RECOVERY	Degrees Farenheit	
	403	Initial Boiling Point
5	448	
10	469	
15	---	
20	491	
30	511	
40	525	
50	539	
60	553	
70	568	
80	586	
90	616	
95	637	
END POINT	657	
RECOVERY	97.5	
RESIDUE	1.7	
LOSS	0.8	

METHOD
Distillation: ASTM D 86

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

South Holland Laboratory

MEMBER ACIL

BEST AVAILABLE COPY

September 24, 1999

CITY OF LAKELAND
3030 E. Lake Parker Dr.
Lakeland, FL 33805
Attn: Steven Parrish

Sample identification by
City of Lakeland

Kind of sample
reported to us #5 Diesel

Sample ID: 570-99

Sample taken at Unit #5 Diesel Tank

Sample taken by City of Lakeland

Date sampled September 20, 1999

Date received September 21, 1999

Analysis Report No. 71-102976

	As Received
GRAVITY	
Specific at 60/60°F	0.8449
Lb/gallon at 60°F	7.036
°API	36.0
HEATING VALUE	
Btu/lb	19,701
Btu/gal at 60°F	138,616
ASH, % Wt.	<.0010
SULFUR, % Wt.	0.04
BOTTOM SEDIMENT AND WATER, % Wt	0.025
FLASH PT. °F	
P-Martens Closed Cup	196
POUR PT. °C	-15
VISCOSITY 100°F cSt	3.445
VISCOSITY 122°F cSt	2.687
CETANE INDEX	51.8
CETANE INDEX	54.0

METHODS
Gravity: ASTM D 287; Heating Value: ASTM D 240; Sulfur: ASTM D 1552; Ash: ASTM D 482
Bottom Sediment & Water: ASTM D 1796; Viscosity: ASTM D 445; Flash Point: ASTM D 93;
Pour Point: ASTM D 97; Cetane Index: ASTM D 976; Cetane Index: ASTM D 4737

Respectfully submitted,
COMMERCIAL TESTING & ENGINEERING CO.

South [illegible] Laboratory

MEMBER ACIL

BEST AVAILABLE COPY

REPORT OF LABORATORY ANALYSTS

LAB NO. ML 8826 SAMPLE MARKED: STK 411 after "Aurora"
SAMPLE DATE: 08-27-99 REPORT DATE: 08-30-99
LOCATION: Port Manatee Client: Coastal Refining & Marketing
SAMPLE SUBMITTED BY: Saybolt
SAMPLE DESCRIPTION : LOW SULFUR DIESEL

TEST	METHOD	RESULT
API GRAVITY AT 60 F.	D1298	36.0
SPECIFIC GRAVITY	D1298	0.8448
FLASH POINT, F. PMCC	D93	188
SEDIMENT & WATER, VOL.%	D2709	0
VISCOSITY AT 100 F., cSt	D445	3.49
VISCOSITY AT 122 F., cSt	D445	2.74
S.U.S. VISCOSITY AT 100 F.	D445	37.6
POUR POINT, F.	D97	+5
SULFUR, WT.%	D4294	0.035
ASH, WT.%	D482	<0.001
B.T.U./GAL. HHV	D240	137342
NITROGEN, PPM	D4629	------
CETANE INDEX, CALCULATED	D976	51
DISTILLATION, IBP	D86	400
10%RECOVERED	D86	465
50%RECOVERED	D86	538
90%RECOVERED	D86	614
FINAL BOILING POINT	D86	656
RECOVERY	D86	98.0
RESIDUE	D86	1.0
LOSS	D86	1.0
TRACE METALS	AA	------
SODIUM, PPM		------
POTASSIUM, PPM		------
SILICON, PPM		------
VANADIUM, PPM		------

BY: Marie Calhoon
MARIE F. CALHOON, CHEMIST

FGT

Last Updated	4/18/02 6:55	
	Total Sulfur Previous Day Avg ppm	Total Sulfur Previous Day Avg Grains/hcf
Station Name	04/16/02	04/16/02
Perry 36" Stream #1	3.1	0.195
Perry 30" Stream #2	3.3	0.205
Perry 24" Stream #3	3.4	0.211
Brooker 24" Stream	4.4	0.276

Florida Gas makes no warranty or representation whatsoever as to the accuracy of the
This information is provided on a best efforts basis and is an estimate.
The information is not used for billing purposes.
Florida Gas is not responsible for any reliance on this information by any party.

Stream History

Gas Day	Index	Perry 36" Stream #1 15SA36PSUL.A Avg ppm	Perry 36" Stream #1 Avg Grains/hcf	Perry 30" Stream #2 15SA30PSUL.A Avg ppm	Perry 30" Stream #2 Avg Grains/h
04/15/02	33	2.412	0.151	2.901	0.181
04/14/02	32	2.761	0.173	1.717	0.107
04/13/02	31	2.492	0.156	1.684	0.105
04/12/02	30	2.169	0.136	1.635	0.102
04/11/02	29	2.319	0.145	1.524	0.095
04/10/02	28	2.431	0.152	1.617	0.101
04/09/02	27	2.464	0.154	2.259	0.141
04/08/02	26	1.910	0.119	1.744	0.109
04/07/02	25	1.428	0.089	1.650	0.103
04/06/02	24	1.480	0.093	1.693	0.106
04/05/02	23	1.918	0.120	1.790	0.112
04/04/02	22	1.663	0.104	1.622	0.101
04/03/02	21	2.973	0.186	2.116	0.132
04/02/02	20	2.080	0.130	0.937	0.059
04/01/02	19	1.750	0.109	1.171	0.073
03/31/02	18	1.297	0.081	1.428	0.089
03/30/02	17	1.293	0.081	2.036	0.127
03/29/02	16	1.610	0.101	1.569	0.098
03/28/02	15	1.718	0.107	2.174	0.136
03/27/02	14	2.166	0.135	2.227	0.139
03/26/02	13	2.962	0.185	1.924	0.120
03/25/02	12	3.112	0.194	2.031	0.127
03/24/02	11	2.527	0.158	2.191	0.137
03/23/02	10	2.147	0.134	2.496	0.156
03/22/02	9	2.205	0.138	2.119	0.132
03/21/02	8	2.214	0.138	1.862	0.116
03/20/02	7	2.404	0.150	1.607	0.100
03/19/02	6	3.120	0.195	1.899	0.119
03/18/02	5	2.792	0.174	2.056	0.128
03/17/02	4	2.436	0.152	2.136	0.134
03/16/02	3	2.307	0.144	2.096	0.131
03/15/02	2	2.069	0.129	1.797	0.112
03/14/02	1	1.634	0.102	2.531	0.158

BTU	Date	CO2	N2	Grav	Methane	Ethane	Propane	Ibutane	Nbutane	IPentan	NPentan	C6	C7	H2	Helium	Oxygen
1029	04-18-2002	0.93	0.28	0.582	96.26	1.956	0.339	0.087	0.068	0.027	0.016	0.036	0	0	0	0
1029	04-17-2002	0.869	0.295	0.582	96.293	1.957	0.342	0.088	0.07	0.028	0.017	0.042	0	0	0	0
1034	04-16-2002	0.922	0.29	0.586	95.788	2.236	0.455	0.119	0.093	0.034	0.019	0.044	0	0	0	0
1029	04-15-2002	0.923	0.291	0.582	96.206	1.976	0.357	0.092	0.073	0.028	0.016	0.037	0	0	0	0
1028	04-14-2002	0.911	0.291	0.581	96.318	1.921	0.329	0.085	0.067	0.026	0.016	0.036	0	0	0	0
1027	04-13-2002	0.916	0.287	0.581	96.366	1.926	0.299	0.076	0.06	0.023	0.014	0.032	0	0	0	0
1027	04-12-2002	0.929	0.296	0.581	96.31	1.948	0.304	0.077	0.061	0.025	0.015	0.036	0	0	0	0
1028	04-11-2002	0.933	0.302	0.582	96.216	1.98	0.337	0.084	0.066	0.027	0.016	0.039	0	0	0	0
1031	04-10-2002	0.908	0.307	0.583	96.054	2.116	0.369	0.091	0.071	0.03	0.019	0.045	0	0	0	0
1029	04-09-2002	0.86	0.304	0.581	96.273	1.997	0.331	0.083	0.064	0.028	0.017	0.042	0	0	0	0
1028	04-08-2002	0.858	0.306	0.58	96.425	1.874	0.317	0.082	0.063	0.025	0.015	0.036	0	0	0	0
1033	04-07-2002	0.894	0.311	0.584	95.964	2.132	0.413	0.104	0.084	0.033	0.019	0.045	0	0	0	0
1031	04-06-2002	0.912	0.327	0.584	95.902	2.26	0.358	0.084	0.066	0.029	0.018	0.043	0	0	0	0
1038	04-05-2002	1.007	0.298	0.59	95.207	2.616	0.531	0.133	0.102	0.039	0.022	0.046	0	0	0	0
1038	04-04-2002	1	0.285	0.589	95.298	2.56	0.515	0.134	0.102	0.039	0.022	0.046	0	0	0	0
1043	04-03-2002	1.002	0.279	0.592	95.012	2.651	0.625	0.166	0.129	0.049	0.027	0.061	0	0	0	0
1047	04-02-2002	0.949	0.286	0.594	94.907	2.649	0.693	0.181	0.156	0.06	0.037	0.082	0	0	0	0
1045	04-01-2002	0.904	0.284	0.592	95.097	2.57	0.652	0.168	0.146	0.058	0.037	0.083	0	0	0	0
1046	03-31-2002	0.921	0.278	0.593	95.063	2.584	0.659	0.171	0.15	0.058	0.036	0.081	0	0	0	0
1045	03-30-2002	0.925	0.289	0.592	95.092	2.552	0.655	0.167	0.147	0.057	0.036	0.081	0	0	0	0
1047	03-29-2002	0.969	0.285	0.594	94.87	2.655	0.698	0.181	0.159	0.06	0.037	0.085	0	0	0	0
1048	03-28-2002	0.929	0.28	0.594	94.91	2.641	0.704	0.182	0.163	0.062	0.039	0.088	0	0	0	0
1048	03-27-2002	0.949	0.281	0.595	94.789	2.713	0.73	0.191	0.164	0.061	0.037	0.085	0	0	0	0
1044	03-26-2002	0.933	0.295	0.592	95.075	2.583	0.643	0.166	0.142	0.054	0.032	0.076	0	0	0	0
1044	03-25-2002	0.922	0.295	0.592	95.131	2.539	0.642	0.167	0.142	0.054	0.032	0.077	0	0	0	0
1042	03-24-2002	0.909	0.288	0.59	95.324	2.463	0.59	0.155	0.128	0.048	0.028	0.068	0	0	0	0
1038	03-23-2002	0.889	0.285	0.588	95.555	2.388	0.523	0.135	0.105	0.041	0.023	0.055	0	0	0	0
1040	03-22-2002	0.839	0.285	0.588	95.574	2.38	0.543	0.142	0.111	0.043	0.025	0.058	0	0	0	0
1042	03-21-2002	0.864	0.281	0.59	95.309	2.524	0.606	0.159	0.124	0.048	0.027	0.06	0	0	0	0
1040	03-20-2002	0.869	0.285	0.588	95.462	2.487	0.53	0.135	0.105	0.043	0.026	0.057	0	0	0	0
1033	03-19-2002	0.919	0.287	0.584	95.757	2.448	0.353	0.083	0.064	0.029	0.019	0.04	0	0	0	0
1032	03-18-2002	0.91	0.282	0.584	95.835	2.4	0.337	0.082	0.065	0.03	0.019	0.041	0	0	0	0
1032	03-17-2002	0.867	0.287	0.583	95.962	2.336	0.324	0.075	0.061	0.028	0.019	0.042	0	0	0	0
1037	03-15-2002	0.899	0.309	0.587	95.55	2.46	0.464	0.115	0.09	0.037	0.022	0.052	0	0	0	0
1041	03-14-2002	0.905	0.311	0.59	95.274	2.546	0.575	0.149	0.115	0.044	0.024	0.057	0	0	0	0
1033	03-13-2002	0.91	0.305	0.584	95.804	2.354	0.369	0.093	0.072	0.031	0.018	0.045	0	0	0	0

TU	Date	CO2	N2	Grav	Methane	Ethane	Propane	Ibutane	Nbutane	IPentan	NPentan	C6	C7+	H2	Helium	Oxygen
1031	03-12-2002	0.946	0.339	0.584	95.763	2.441	0.302	0.071	0.055	0.025	0.016	0.042	0	0	0	0
1030	03-11-2002	0.897	0.323	0.583	95.961	2.303	0.306	0.071	0.056	0.025	0.016	0.042	0	0	0	0
1030	03-10-2002	0.965	0.302	0.584	95.866	2.34	0.307	0.075	0.059	0.026	0.016	0.042	0	0	0	0
1029	03-09-2002	0.918	0.295	0.582	96.125	2.195	0.27	0.069	0.055	0.024	0.014	0.037	0	0	0	0
1029	03-08-2002	0.873	0.287	0.581	96.181	2.18	0.279	0.07	0.056	0.024	0.014	0.036	0	0	0	0
1028	03-07-2002	0.88	0.303	0.581	96.275	2.061	0.277	0.068	0.057	0.025	0.015	0.038	0	0	0	0
1027	03-06-2002	0.781	0.31	0.579	96.625	1.816	0.264	0.065	0.054	0.026	0.017	0.042	0	0	0	0
1026	03-05-2002	0.745	0.321	0.578	96.681	1.842	0.227	0.054	0.045	0.024	0.016	0.044	0	0	0	0
1028	03-04-2002	0.791	0.339	0.58	96.45	1.927	0.28	0.064	0.054	0.029	0.02	0.047	0	0	0	0
1028	03-03-2002	0.882	0.289	0.581	96.329	2.004	0.284	0.068	0.056	0.027	0.018	0.043	0	0	0	0
1028	03-02-2002	0.916	0.28	0.581	96.152	2.211	0.259	0.058	0.048	0.024	0.015	0.037	0	0	0	0
1028	03-01-2002	0.931	0.276	0.581	96.113	2.285	0.229	0.053	0.044	0.021	0.014	0.035	0	0	0	0
1028	02-28-2002	0.942	0.28	0.582	96.043	2.363	0.213	0.049	0.041	0.02	0.013	0.036	0	0	0	0
1030	02-27-2002	0.935	0.284	0.583	95.955	2.369	0.265	0.061	0.052	0.024	0.016	0.039	0	0	0	0
1029	02-26-2002	0.945	0.283	0.583	95.904	2.422	0.27	0.057	0.048	0.022	0.015	0.033	0	0	0	0
1029	02-26-2002	0.911	0.304	0.582	95.917	2.441	0.26	0.051	0.044	0.021	0.015	0.034	0	0	0	0
1029	02-24-2002	0.97	0.299	0.583	95.803	2.498	0.267	0.053	0.044	0.021	0.014	0.032	0	0	0	0
1029	02-23-2002	1.011	0.297	0.584	95.728	2.518	0.272	0.057	0.047	0.022	0.014	0.035	0	0	0	0
1033	02-22-2002	0.996	0.279	0.586	95.616	2.497	0.367	0.085	0.069	0.03	0.018	0.044	0	0	0	0
1032	02-21-2002	1.005	0.273	0.585	95.682	2.495	0.321	0.075	0.061	0.028	0.018	0.044	0	0	0	0
1032	02-20-2002	1.03	0.269	0.585	95.616	2.568	0.302	0.07	0.057	0.027	0.017	0.044	0	0	0	0
1032	02-19-2002	1.062	0.28	0.586	95.4	2.742	0.306	0.07	0.057	0.027	0.017	0.039	0	0	0	0
1034	02-18-2002	1.02	0.314	0.587	95.307	2.793	0.345	0.071	0.059	0.029	0.019	0.043	0	0	0	0
1035	02-17-2002	1.002	0.308	0.588	95.281	2.761	0.689	0.087	0.071	0.033	0.022	0.047	0	0	0	0
1036	02-16-2002	0.985	0.3	0.588	95.271	2.759	0.413	0.095	0.077	0.034	0.022	0.045	0	0	0	0
1035	02-15-2002	1	0.271	0.587	95.441	2.622	0.398	0.094	0.075	0.033	0.021	0.045	0	0	0	0
1033	02-14-2002	0.932	0.299	0.585	95.675	2.515	0.346	0.079	0.064	0.029	0.019	0.041	0	0	0	0
1034	02-13-2002	0.909	0.332	0.585	95.644	2.49	0.364	0.089	0.072	0.033	0.022	0.045	0	0	0	0
1033	02-12-2002	0.946	0.301	0.585	95.664	2.449	0.374	0.094	0.076	0.033	0.02	0.043	0	0	0	0
1035	02-11-2002	0.928	0.298	0.586	95.646	2.445	0.399	0.098	0.081	0.035	0.022	0.048	0	0	0	0
1033	02-10-2002	0.926	0.274	0.585	95.796	2.377	0.36	0.091	0.075	0.033	0.021	0.048	0	0	0	0
1033	02-09-2002	0.947	0.276	0.585	95.756	2.411	0.352	0.088	0.072	0.032	0.02	0.046	0	0	0	0
1035	02-08-2002	0.897	0.277	0.585	95.75	2.413	0.384	0.094	0.077	0.035	0.022	0.05	0	0	0	0
1036	02-07-2002	0.856	0.284	0.585	95.798	2.348	0.403	0.102	0.086	0.039	0.026	0.058	0	0	0	0
1035	02-06-2002	0.879	0.273	0.585	95.727	2.433	0.404	0.096	0.079	0.035	0.023	0.05	0	0	0	0
1039	02-05-2002	0.9	0.272	0.588	95.44	2.556	0.468	0.118	0.1	0.041	0.027	0.057	0	0	0	0

BEST AVAILABLE COPY

BTU	Date	CO2	N2	Grav	Methane	Ethane	Propane	Ibutane	Nbutane	IPentan	NPentan	C6	C7	H2	Helium	Oxygen
1042	02-04-2002	0.882	0.276	0.59	95.239	2.638	0.561	0.138	0.119	0.048	0.03	0.068	0	0	0	0
1039	02-03-2002	0.866	0.272	0.588	95.462	2.578	0.489	0.115	0.094	0.04	0.025	0.058	0	0	0	0
1040	02-02-2002	0.886	0.276	0.588	95.492	2.446	0.522	0.133	0.108	0.044	0.027	0.066	0	0	0	0
1040	02-01-2002	0.889	0.293	0.588	95.456	2.464	0.523	0.13	0.109	0.044	0.026	0.065	0	0	0	0
1038	01-31-2002	0.914	0.299	0.588	95.515	2.42	0.494	0.123	0.103	0.042	0.026	0.064	0	0	0	0
1033	01-30-2002	0.908	0.305	0.585	95.854	2.286	0.373	0.09	0.076	0.034	0.021	0.054	0	0	0	0
1035	01-29-2002	0.944	0.304	0.587	95.608	2.404	0.43	0.106	0.089	0.037	0.022	0.057	0	0	0	0
1036	01-28-2002	0.936	0.283	0.587	95.594	2.435	0.441	0.109	0.09	0.036	0.021	0.055	0	0	0	0
1040	01-27-2002	0.915	0.285	0.589	95.422	2.466	0.529	0.135	0.111	0.044	0.026	0.066	0	0	0	0
1044	01-26-2002	0.928	0.29	0.592	95.042	2.648	0.64	0.163	0.133	0.051	0.029	0.074	0	0	0	0
1044	01-25-2002	0.964	0.296	0.592	95.023	2.633	0.631	0.164	0.132	0.052	0.029	0.075	0	0	0	0
1043	01-24-2002	0.999	0.291	0.592	94.965	2.679	0.628	0.164	0.131	0.049	0.027	0.067	0	0	0	0
1039	01-23-2002	1.021	0.299	0.59	95.157	2.615	0.536	0.139	0.11	0.042	0.023	0.058	0	0	0	0
1035	01-22-2002	1.013	0.308	0.588	95.4	2.575	0.416	0.104	0.083	0.033	0.019	0.05	0	0	0	0
1037	01-21-2002	0.95	0.324	0.588	95.422	2.523	0.453	0.116	0.093	0.039	0.023	0.058	0	0	0	0
1036	01-20-2002	0.961	0.297	0.587	95.507	2.471	0.446	0.114	0.092	0.037	0.021	0.054	0	0	0	0
1036	01-19-2002	0.932	0.294	0.586	95.604	2.432	0.432	0.11	0.09	0.036	0.021	0.051	0	0	0	0
1034	01-18-2002	0.938	0.327	0.586	95.652	2.38	0.409	0.102	0.086	0.035	0.02	0.05	0	0	0	0

BEST AVAILABLE COPY

NO. 2 FUEL OIL SEGMENT COMMENT

This attachment contains the MSDS sheet for a fuel additive used on the fuel oil for the emission unit. This additive is an EPA approved fuel enzyme that is used to prevent breakdown of the fuel by bacteria and to improve the combustion process there-by reducing the amount of CO generated. The fuel additive will be used at a rate of 1 gallon per 4,000 gallons of fuel oil. This product has been approved for use by Siemens Westinghouse Power Corporation.

Soltron Safety Data Sheet
Date Prepared: 3/1/00

SOLTRON™ MATERIAL SAFETY DATA SHEET

1. CHEMICAL PRODUCT AND COMPANY IDENTIFICATION

Material Identity

Product Name:	*Soltron™*
General or Generic ID:	LOW ODOR BASED SOLVENT

Company:
SOLPOWER CORPORATION
Suite 102
7309 East Stetson Dr.
Scottsdale, Arizona 85251

Emergency Telephone Number
INFOTRAC (1-800-535-5053)
24 hours everyday

Regulatory Information Number:
(1-480-947-6366)

2. COMPOSITION INFORMATION ON INGREDIENTS

Ingredients (s)	CAS Number	% (by weight)
Aliphatic Hydrocarbon	64742-96-7	>99.5
Proprietary Organic Compounds		< 0.5

3. HAZARDS IDENTIFCATION

Potential Health Effects

Eye Can cause eye irritation. Symptoms include stinging, tearing, redness and swelling of eyes.

Skin May cause mild skin irritation. Prolonged or repeated contact may dry the skin. Symptoms may include redness, burning, drying and cracking, and skin burns.

Swallowing Swallowing small amounts of this material during normal handling is not likely to cause harmful effects. Swallowing large amounts may be harmful. This material can get into the lungs during swallowing or vomiting. This results in lung inflammation and other lung injury.

Inhalation Breathing of vapor mist is possible. Breathing small amounts of this material during normal handling is not likely to cause harmful effects. Breathing large amounts may be harmful.

Symptoms Of Skin Exposure

Signs and symptoms of exposure to this material through breathing, swallowing, and/or passage of the material through the skin may include: stomach or intestinal upset (nausea, vomiting, diarrhea) irritation (nose, throat, airways), central nervous symptom depression (dizziness, drowsiness, weakness, fatigue, nausea, headache, unconsciousness), and death.

Target Organ Effects	No data.
Developmental Information	No data.
Cancer Information	No data.

Other Health Effects	No data.
Primary Route (s) of Entry	Inhalation, Skin contact

4. FIRST AID MEASURES

Eyes	If symptoms develop, immediately move individual away from exposure and into fresh air. Flush eyes gently with water for at least 15 minutes while holding eyelids apart; seek immediate medical attention.
Skin	Remove contaminated clothing. Wash exposed area with soap and water. If symptoms persist, seek medical attention. Launder clothing before reuse.
Swallowing	Seek medical attention. If individual is drowsy or unconscious, do not give anything by mouth; place individual on the left side with head down. Contact a physician, medical facility or poison control center for advice about whether to induce vomiting. If possible, do not leave individual unattended.
Inhalation	If symptoms develop, move individual away from exposure and into fresh air. If symptoms persist, seek medical attention. If breathing is difficult, administer oxygen. Keep person warm and quiet; seek immediate medical attention.
Note to Physicians	This material is an aspiration hazard. Potential danger from aspiration must be weighed against possible oral toxicity (see section 3 - Swallowing) when deciding whether to induce vomiting. Preexisting disorders of the following organs (or organ systems) may be aggravated by exposure to this material: skin, lung (for example asthma-like conditions).

5. FIRE FIGHTING MEASURES

Flash Point	°F, T.C.C – 150 (65.5°C)
Explosive Limit	(For component) Lower 0.9% Upper .0%
Auto ignition Temperature	No data.
Hazardous Products of Combustion	May form: carbon dioxide and carbon monoxide, various hydrocarbons.
Fire and Explosion Hazards	Vapors are heavier than air and may travel along the ground or are moved by ventilation and ignited by heat, pilot lights, other flames and ignitions sources at locations distant from material handing point. Never use welding or cutting torch on or near drum (even empty) because product (even just residue) can ignite explosively.
Extinguishing Media	Regular foam, water fog, carbon dioxide, dry chemical
Fire Fighting Instructions	Wear a self-contained breathing apparatus with a full-face piece operated in the positive pressure demand mode with appropriate turnout gear and chemical resistant personal protective equipment. Refer to the personal protective equipment section of this MSDS.
NFPA Rating	Health - 0, Flammability - 1, Reactivity - 0.

6. ACCIDENTAL RELASE MEASURES

Small Spill	Absorb liquid on vermiculite, floor absorbent, or the absorbent material and transfer to hood.
Large Spill	Eliminate all ignition sources (flares, flames including pilot lights, electrical sparks). Persons not wearing protective equipment should be excluded from area of spill until clean up has been completed. Stop spill at source. Prevent from entering drains, sewers, streams, or other bodies of water. Prevent from spreading. If runoff occurs, notify authorities as required. Pump or vacuum transfer-spilled product to clean containers for recovery. Absorb unrecoverable product. Transfer contaminated absorbent soil and other materials to container for disposal.

7. HANDLING AND STORAGE

Handling	Containers of this material may be hazardous when emptied. Since emptied containers retain product residues (vapors, liquid and/or solids), all hazard precautions given in the data sheet must be observed.

8. EXPOSURE CONTROLS/PERSONAL PROTECTION

Eye protection	Chemical splash goggles and in compliance with OSHA regulations are advised; however, OSHA regulations also permit other type safety glasses. (Consult your safety representative.)
Skin Protection	Wear resistant gloves such as: nitrile rubber. To prevent repeated or prolonged skin contact, wear impervious clothing and boots.
Respiratory Protections	If workplace exposure limit(s) of product or any component is exceeded (see exposure guidelines) a NIOSH/MSHA approved air supplied respirator is advised in absence of proper environmental control. OSHA regulations also permit other NIOSH/MSHA respirators. (Negative pressure type) under specified conditions (see your industrial hygienist). Engineering or administrative controls should be implemented to reduce exposure.
Engineering Controls	Provide sufficient mechanical (general and/or local exhaust) ventilation to maintain exposure below TLV(s)
Exposure Guidelines	ALIPHATIC HYDROCARBON (64742-96-7) No exposure limits established.

9. PHYSICAL AND CHEMICAL PROPERTIES

Boiling Point(For component)	350.0°F (176.6°C) @ 760 mmHg
Vapor Pressure	(For component) .010 mmHg @ 100.00°F
Specific Vapor Density	5.900 @ AIR=1
Specific Gravity	.804 @ 60.00°F
Liquid Density	6.700 lbs/gal @ 60.00°F .804 kg/l @ 16.00°C
Percent Volatiles	100.000%

Percent Volatile Organic Compounds	100.000%, 804.000 g/l, 6.700 lbs/gal
Evaporation Rate	200.00
Appearance	No data.
State	LIQUID.
Physical Form	NEAT.
Color	CLEAR & COLORLESS
Odor	LOW MILD ODOR
PH	No Data.

10. STABILITY AND REACTIVITY

Hazardous Polymerization	Product will not undergo hazardous polymerization.
Hazardous Decompositions	May form: carbon dioxide and carbon monoxide, various hydrocarbons.
Chemical Stability	Stable.
Incompatibility	Avoid contact with: strong oxidizing agents

11. TOXICOLOGICAL INFORMATION

No Data.

12. ECOLOGICAL INFORMATION

No Data

13. DISPOSAL CONSIDERATION

Waste Management Information	Dispose of in accordance with all applicable local, state and federal regulations.

14. TRASPORT INFORMATION

DOT INFORMATION – 49 CFR 172.101

DOT Description: LOW ODOR BASE ALIPHATIC HYDROCARBON, COMBUSTABLE LIQUID, UN1223 (for Air Shipment), N1268 (for Ground Shipment), III.

Container/Mode: 7 fl. oz., 32 fl. oz, 1 Gallon, 5 Gallon Pail, 55 Gallon Drum

NOS Component: None.

RQ (Reporting Quantity) – 49 CFR 172.101 Not applicable.

15. REGULATORY INFORMATION

US Federal Regulations

TSCA (Toxic Substance Control Act) Status
TSCA (UNITED STATES) The international ingredients of the product are listed.
CERCLA RQ – 40 CFR 302.4
None
SARA 302 Components – 40 CFR 355 Appendix A
None
Section 311/312 Hazard Class – 40 CFR 370.2
Immediate (X) Delayed ( ) Fire (X) Reactive ( ) Sudden Release of Pressure ( )
SARA 313 Components – 40 CFR 372.65
None

International Regulations

Inventory Status
DSL (CANADA) The intentional ingredients of this product are listed.
EINECS (EUROPE) The intentional ingredients of this product are listed.

State and Local Regulations

California Proposition 65

The following statement is made in order to comply with the California Safe Drinking Water and Toxic Enforcement Act of 1966: The product contains the following substance(s) known to the state of California to cause cancer.

BENZENE

The following statement is made in order to comply with the California Safe Drinking Water and Toxic Enforcement Act of 1966: The product contains the following substance(s) known to the state of California to cause reproductive harm.

TOLUENE

16. OTHER INFORMATION

The information accumulated herein is believed to be accurate but is not warranted to be whether originating with the company or not. Recipients are advised to confirm in advanced of need that the information is current, applicable, and suitable to their circumstances.

17. OTHER INFORMATION

This Material Safety Data was prepared by Solpower Corporation in accordance with 29 CFR 1910.1200. All information, recommendations and suggestions appearing herein concerning this product are based upon tests and data believed to reliable, however it is the users responsibility to determine the safety, toxicity and suitability for his own use of the product described herein. Since the actual use by others is beyond our control, no guarantee expressed or implied is made Solpower Corporation as to the effects of such use, the results to be obtained or the safety and toxicity of the product nor does Solpower Corporation assume any liability arising out of use by other of the product referred to herein. Nor is the information herein to be construed as absolutely complete since additional information may be necessary or desirable when particular or exceptional conditions or circumstances exist or because of applicable laws or government regulations.

ATTACHMENT MC-EU6-J3

DESCRIPTION OF CONTROL EQUIPMENT

CO SYSTEM DESIGN BASIS:

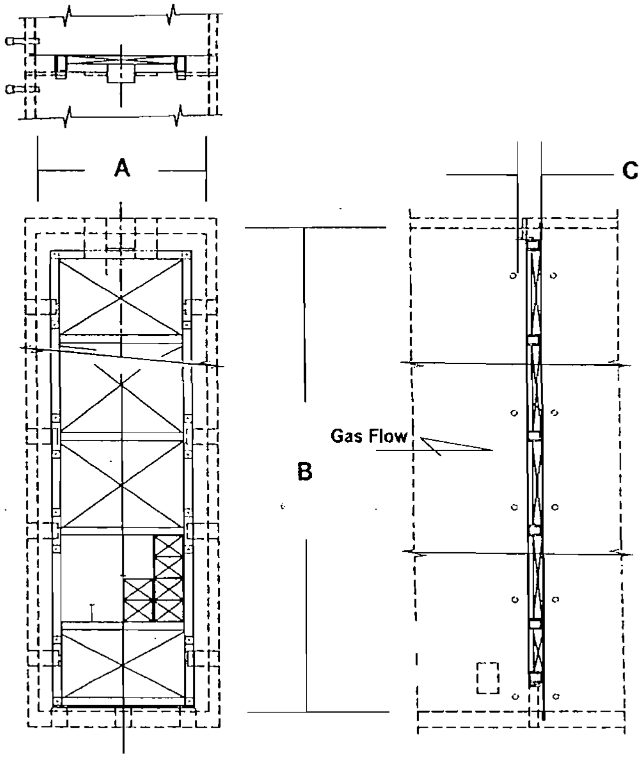
Gas Flow from:	Combustion Turbine – Combined Cycle
Gas Flow:	Horizontal
Fuel:	Natural Gas and Oil
Gas Flow Rate (At catalyst face):	Designed for gas velocities within ±15% of the mean velocity at the catalyst face
Temperature (At catalyst face):	Designed for gas temperatures within range ±25°F of given average temperatures at all points at the catalyst face
CO Concentration (At catalyst face):	226 lb/hr (NG) // 320 lb/hr (Oil)
CO Reduction:	Design 1 - 90% CO Reduction-Full Load Design 2 – 95% CO Reduction-Full Load Design 3 – 98% CO Reduction-Full Load
VOC Concentration (At catalyst face):	Not Given
VOC Reduction:	Advise – all designs
VOC Composition:	Non-Methane / Non-Ethane – 50% Saturated
HRSG Dimensions:	62.5 ft H x 37 ft W (Gas Path – 58.5 H)

CATALYST MODULES

The CO Catalyst is manufactured with a special stainless steel foil substrate which is corrugated and coated with an alumina washcoat. The washcoat is impregnated with platinum group metals. The catalyzed foil is folded and encased in welded steel frames, approximately 2 ft. square, to form individual modules. Nine (9) of the modules are provided with four removable and replaceable test buttons which provide ability to monitor catalyst life – 36 total test buttons provided.

INTERNAL SUPPORT FRAME & SEALS

The internal support frame and internal gas seals are fabricated from standard structural Carbon Steel members and shapes. Mechanical gas and groove expansion seals around the perimeter of the frame and inside the liner sheet prevent bypass around the catalyst. Design accommodates movement of the frame due to thermal expansion while maintaining a continuous seal. The internal frame system interfaces with two types of customer provided connections; ductplate mounted slide plates and liner sheet grooves, both designed by Engelhard.



Dimensions:

Inside Liner Width	**(A)**	**37 ft**
Inside Liner Height	**(B)**	**62.5 ft**
Gas Path Height		**58.5 ft**
Catalyst + frame depth	**(C)**	**18" Max.**

Estimated Weights:
Frame and Seals + Catalyst Modules –

Design 1	**Design 2**	**Design 3**
57,000 lb	**62,000 lb**	**70,000 lb**

The materials are supplied by Engelhard and installed by others in accordance with the Engelhard design and installation instructions. The frame and seal installation must be inspected by Engelhard prior to initial turbine firing. The CO Catalyst modules should be installed after initial turbine firing.

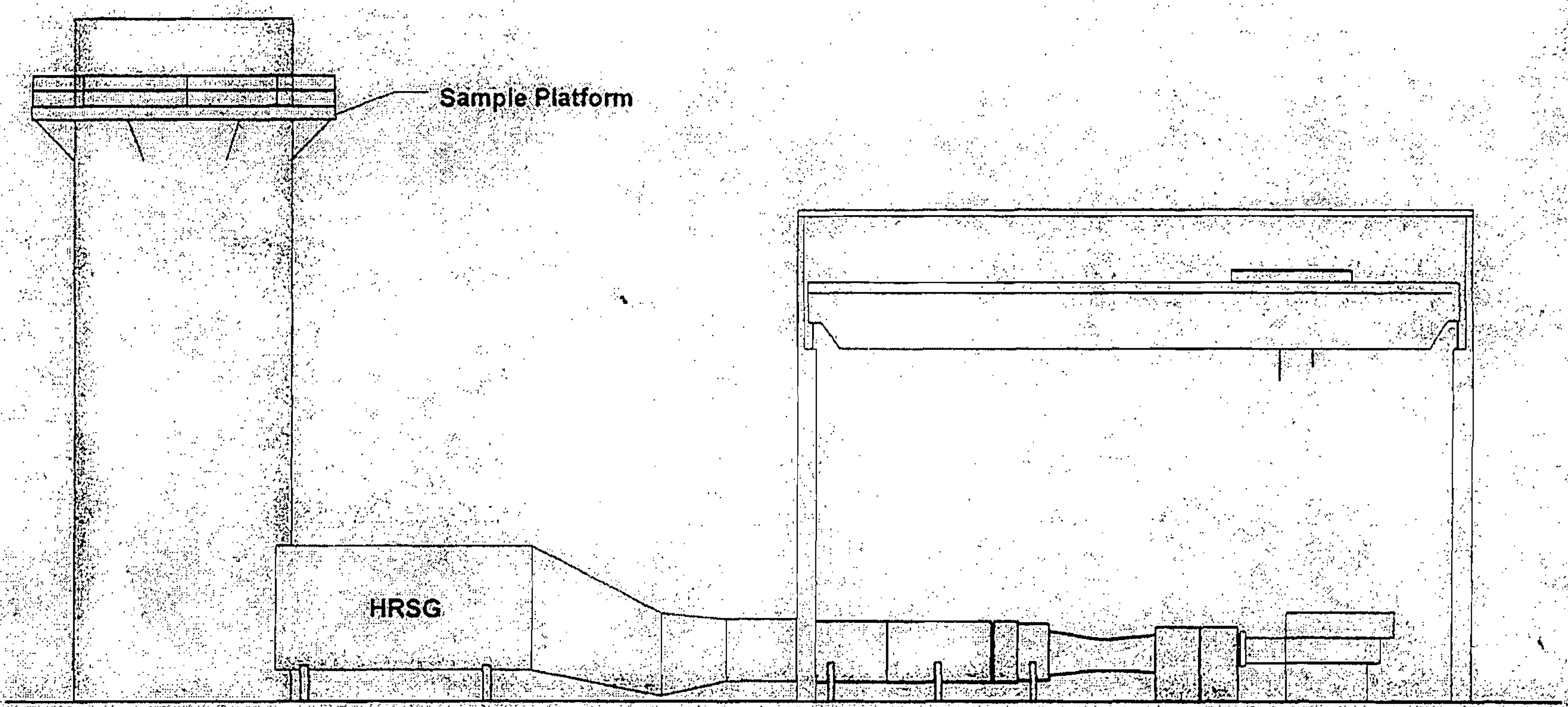
QUALITY ASSURANCE and SAFETY

Engelhard's manufacturing is carried out under strict adherence to published quality control and statistical process control programs. and strict adherence to Corporate safety practices and procedures.

ATTACHMENT MC-EU6-J4

DESCRIPTION OF STACK SAMPLING FACILITIES

Catalyst
Air Management, Inc.



GENERAL ARRANGEMENT

TITLE
CITY OF LAKELAND - C.D. McINTOSH POWER PLANT

DESCRIPTION
GENERAL ARRANGEMENT - UNIT 5

DATE
3/02/02

SCALE
None

DRAWN BY
MT TAYLOR

REVISED

ATTACHMENT MC-EU6-J5

COMPLIANCE TEST REPORT

ATTACHMENT MC-EU6-J5

COMPLIANCE TEST REPORT

Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in the air construction permit.

Permittee will submit a properly signed and sealed certification from the permittee's Professional Engineer stating that 1) the construction of the emissions unit was completed in accordance with the AC permit and 2) the emissions unit has been tested and compliance with the terms and conditions contained within the AC permit has been properly demonstrated within 45 days after completion of all of the initial performance tests.

[Rules 62-212.400(7)(b), 62-213.440(2), and 62-213.420(1)(a)5, F.A.C.]

CATALYST
AIR MANAGEMENT, INC

CITY OF LAKELAND
C.D. McINTOSH POWER PLANT
UNIT 5

EMISSIONS TEST REPORT

CATALYST AIR MANAGEMENT, INC.
REPORT NUMBER 138-049

JUNE 10, 2002

Prepared for
City of Lakeland
C.D. McIntosh Power Plant
3030 East Lake Parker Drive
Lakeland, FL 33805

PROJECT FACT SHEET

NAME OF SOURCE OWNER:	City of Lakeland
SOURCE IDENTIFICATION:	C.D. McIntosh Unit 5 Facility ID No. 1050004 E.U. ID No. 028
LOCATION OF SOURCE:	3030 East Lake Parker Drive Lakeland, FL
TYPE OF OPERATION:	Combustion Turbine Generating Unit
TYPES OF TESTS PERFORMED:	Oxygen/Carbon Dioxide-EPA Method 3A Carbon Monoxide-EPA Method 10 Nitrogen Oxide-EPA Method 20 VOC-EPA Method 25A
SOURCE ANALYZERS:	Siemans 300-CLD NOx – 28J04015 Siemans Oxymat 6E O_2 – N1K80365
TEST COMPANY:	Catalyst Air Management, Inc. 2505 Byington-Solway Road Knoxville, TN 37931
SITE SUPERVISOR:	Mike Taylor - Principal
TEST PERSONNEL:	Josh Nicely - Lead Technician
REPORT PREPARATION:	Mike Taylor - Principal
TEST DATES:	May 3-6, 2002
OWNERS REPRESENTATIVE:	John Guiseppi Andrew Nguyen
TEST OBSERVER:	Bob Soich - FDEP

1.0 Introduction

Catalyst Air management, Inc. (Catalyst) was contracted by the City of Lakeland to perform the performance test for initial compliance during combined cycle operation at C.D. McIntosh, Unit 5.

The sampling program was conducted May 3 through 6, 2002. The testing was performed by Messers. Mike Taylor and Josh Nicely of Catalyst, with the assistance of personnel assigned by Lakeland. Mr. John Guiseppi of Lakeland coordinated plant operation during the testing.

2.0 Summary of Test Results

A summary of test results developed by this source sampling program are presented in Table 1. The summary tables are presented as follows:

3.0 Results of Testing

The results from the compliance test are tabulated in Appendix. They indicate that the emissions are in compliance with standards ofTitle V Permit Number 1050004-009-AV.

TABLE 1
Emissions Summary
Base Load

Parameter	ppm @ 15% O_2	Permitted ppm	Actual lb/mmBtu
NOx	7.2	7.5	0.026
CO	1.0	25.0	0.002
VOC	0.1	4.0	0.001

TABLE 2

Emissions Summary
Power Augmentation

Parameter	ppm @ 15% O_2	Permitted ppm	Actual lb/mmBtu
NOx	7.0	7.5	0.026
CO	2.0	25.0	0.005
VOC	0.3	4.0	0.001

TABLE 3

Emissions Summary
90% Load

Parameter	ppm @ 15% O_2	Permitted ppm	Actual lb/mmBtu
NOx	7.0	7.5	0.026
CO	1.7	25.0	0.004
VOC	0.1	4.0	0.000

TABLE 4

Emissions Summary
80% Load

Parameter	ppm @ 15% O_2	Permitted ppm	Actual lb/mmBtu
NOx	6.8	7.5	0.025
CO	2.6	25.0	0.006
VOC	0.2	4.0	0.001

TABLE 5
Emissions Summary
70% Load

Parameter	ppm @ 15% O_2	Permitted ppm	Actual lb/mmBtu
NOx	6.8	7.5	0.025
CO	22.6	25.0	0.051
VOC	0.1	4.0	0.001

4.0 Description Of Combustion Units

McIntosh Unit 5 is a Westinghouse 501G combustion turbine (CT) with a heat recovery steam generator (HRSG). The CT can be fired with natural gas and No.2 distillate fuel oil. NOx emissions are controlled by low NOx combustion and selective catalytic reduction (SCR).

The maximum heat input of the unit is 2407 MMBtu/hr based on the lower heating value (MMBtu/hr, LHV) while firing natural gas and 2236 MMBtu/hr, LHV while firing fuel oil. The rated combined capacity of the CT/HRSG is approximately 350 MW gross.

The Unit 5 stack height is approximately 300 feet. The testing location is located on the stack approximately 160 ft above the inlet duct. Four test ports facilitate the sampling. A schematic of the stack sampling location is included.

5.0 Description of CEMS

The Unit 5 CEMS is an extraction system that measures NOx and O_2 concentrations at the sampling location. The CEMS analyzers include a Siemans Model 300-CLD NOx analyzer and a Siemans Model Oxymat 6E O_2 analyzer. The recording and reporting requirements are performed by a computerized data acquisition and handing system (DAHS).

Unit 5 CEMS
(1) Siemans NOx – 300-CLD - Serial No. 28J04015
(1) Siemans O_2 – Oxymat 6E - Serial No. N1K80365

The data acquisition and handling system utilizes a Fc factor based on the fuel (8710 or 9190 scf/mmBtu) to calculate NOx emissions in lbs/mmBtu. The SO_2 and CO_2 emissions are calculated and reported in accordance with procedures in 40 CFR Part 75, Appendices D and G.

TABLE 6

Test Summary

Gas - EPA Method 3A, 10, 20, 25A

Run #	Date	Start Time	End Time	Load	NOx ppm	NOx @15% ppm	NOx lb/mmBtu	CO ppm	CO @15% ppm	CO lbs/mmBtu	VOC ppm	VOC @15% ppm	VOC lbs/mmBtu	O_2 %
1	5/3/02	0:48	2:34	70%	8.3	7.0	0.026	27.4	23.1	0.052	0.2	0.1	0.001	13.9
2	5/3/02	2:54	3:54	70%	7.9	6.7	0.025	25.7	21.7	0.049	0.2	0.1	0.000	13.9
3	5/3/02	4:01	5:01	70%	7.8	6.6	0.024	27.4	23.1	0.052	0.2	0.2	0.001	13.9
1	5/3/02	5:30	6:30	80%	8.4	6.6	0.024	3.4	2.7	0.006	0.2	0.2	0.001	13.4
2	5/3/02	6:39	7:39	80%	8.7	7.0	0.026	3.1	2.5	0.006	0.2	0.2	0.001	13.6
3	5/3/02	7:48	8:48	80%	8.6	6.9	0.025	3.1	2.5	0.006	0.2	0.2	0.001	13.5
1	5/5/02	18:30	19:30	90%	8.5	6.8	0.025	2.1	1.7	0.004	0.1	0.1	0.000	13.5
2	5/5/02	19:40	20:40	90%	9.1	7.2	0.026	2.0	1.6	0.004	0.1	0.1	0.000	13.4
3	5/5/02	20:50	21:50	90%	8.9	7.1	0.026	2.3	1.8	0.004	0.1	0.1	0.000	13.5
1	5/3/02	15:30	16:30	Base	9.4	7.3	0.027	1.6	1.2	0.003	0.2	0.2	0.001	13.3
2	5/6/02	7:41	8:41	Base	9.4	7.1	0.026	1.1	0.8	0.002	0.1	0.1	0.000	13.1
3	5/6/02	8:50	9:50	Base	9.5	7.2	0.026	1.3	1.0	0.002	0.1	0.1	0.000	13.1
1	5/6/02	12:10	13:10	Power Aug	8.8	6.7	0.025	3.5	2.6	0.006	0.3	0.2	0.001	13.1
2	5/6/02	13:15	14:15	Power Aug	9.2	7.1	0.026	2.5	1.9	0.004	0.4	0.3	0.001	13.3
3	5/6/02	14:25	15:25	Power Aug	10.2	7.3	0.027	2.2	1.6	0.004	0.4	0.3	0.001	12.7

VISIBLE EMISSION OBSERVATION FORM

No. 1/2

COMPANY NAME
CITY OF LAKELAND

STREET ADDRESS
3030 E. LAKE PARKER DR

UNIT-5 COMBUSTION TURBINE

CITY
LAKELAND

STATE
FL

ZIP
33805

PHONE (KEY CONTACT)
863 834 6600

SOURCE ID NUMBER
1050004 EUID 028

PROCESS EQUIPMENT
U5 COMBUSTION TURBINE

OPERATING MODE
BASE LOAD

CONTROL EQUIPMENT
SCR NONE

OPERATING MODE
~~IN SERVICE~~

DESCRIBE EMISSION POINT
STACK EXIT - TALL CONCRETE STACK

HEIGHT ABOVE GROUND LEVEL
≈ 300'

HEIGHT RELATIVE TO OBSERVER
Start ~300' End ~300'

DISTANCE FROM OBSERVER
Start ~1100' End ~1100

DIRECTION FROM OBSERVER
Start W End W

DESCRIBE EMISSIONS
Start CT EXHAUST End CT EXHAUST

EMISSION COLOR
Start CLEAR End CLEAR

IF WATER DROPLET PLUME
Attached ☐ NONE Detached ☐

POINT IN THE PLUME AT WHICH OPACITY WAS DETERMINED
Start STACK EXIT End STACK EXIT

DESCRIBE PLUME BACKGROUND
Start SKY + CLOUDS End SKY + CLOUDS

BACKGROUND COLOR
Start LT BLUE End LT BLUE

SKY CONDITIONS
Start SCATTERED End SCATTERED

WIND SPEED
Start 0-2 End 0-2

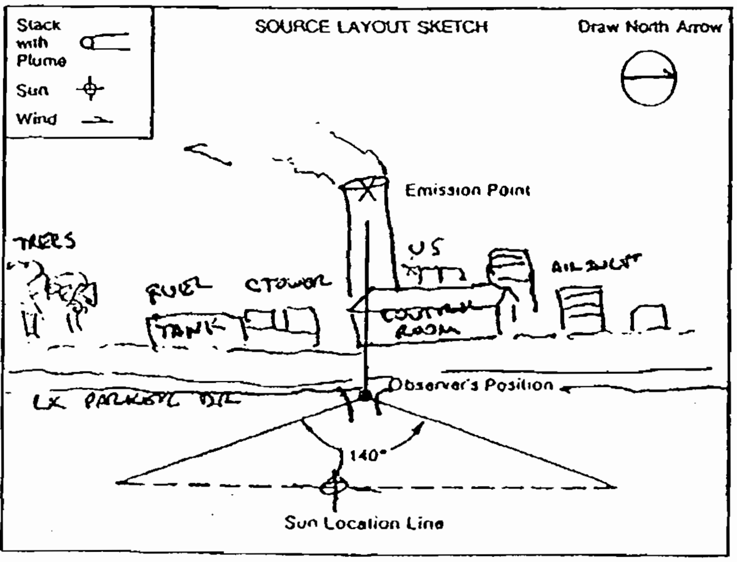
WIND DIRECTION (FROM)
Start NNE End NNE

AMBIENT TEMP
Start 79.0 End 82.0

WET BULB TEMP
75.1

RH, percent
83.5%

SOURCE LAYOUT SKETCH



ADDITIONAL INFORMATION

INCLINE = 15.2° HIGH SET ANG ≈ 0

OBSERVATION DATE

START TIME
07:41

END TIME
0810

SEC / MIN	0	15	30	45	COMMENTS
41	0	0	0	0	
2	0	0	0	0	
3	0	0	0	0	
4	0	0	0	0	
5	0	0	0	0	
6	0	0	0	0	
7	0	0	0	0	
8	0	0	0	0	
9	0	0	0	0	
5 10	0	0	0	0	
11	0	0	0	0	
12	0	0	0	0	
13	0	0	0	0	
14	0	0	0	0	
15	0	0	0	0	
16	0	0	0	0	
17	0	0	0	0	
18	0	0	0	0	
19	0	0	0	0	
800	0	0	0	0	
21	0	0	0	0	
22	0	0	0	0	
23	0	0	0	0	
24	0	0	0	0	
25	0	0	0	0	
26	0	0	0	0	
27	0	0	0	0	
28	0	0	0	0	
29	0	0	0	0	
8 10	0	0	0	0	

OBSERVER'S NAME (PRINT)
JOHN GUISEPPI

OBSERVER'S SIGNATURE

DATE
6 MAY 02

ORGANIZATION
CITY OF LAKELAND

CERTIFIED BY
EASTERN TECHNICAL ASSOCIATION

DATE
14 FEB 02

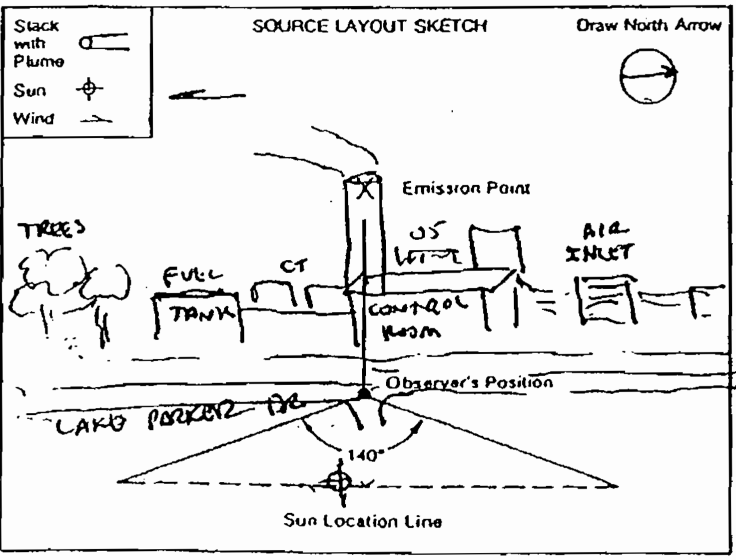
CONTINUED ON VEO FORM NUMBER
2/2

VISIBLE EMISSION OBSERVATION FORM CEM TIME No. 2/2

COMPANY NAME CITY OF LAKELAND	
STREET ADDRESS 3030 E. LAKE PARKER DR	
UNIT-5 COMBUSTION TURBINE	
CITY LAKELAND	STATE FL
ZIP 33805	
PHONE (KEY CONTACT) 863 834 6600	SOURCE ID NUMBER 1050004 EU ID 028
PROCESS EQUIPMENT U5 COMBUSTION TURBINE	OPERATING MODE BASE LOAD
CONTROL EQUIPMENT ~~SCR~~ NONE	OPERATING MODE ~~IN SERVICE~~
DESCRIBE EMISSION POINT STACK EXIT – TALL CONCRETE STACK	
HEIGHT ABOVE GROUND LEVEL ≈ 300′	HEIGHT RELATIVE TO OBSERVER Start ≈300′ End ≈300′
DISTANCE FROM OBSERVER Start ≈1100′ End ≈1100′	DIRECTION FROM OBSERVER Start W End W
DESCRIBE EMISSIONS Start CT EXHAUST	End CT EXHAUST
EMISSION COLOR Start CLEAR End CLEAR	IF WATER DROPLET PLUME Attached ☐ NONE Detached ☐
POINT IN THE PLUME AT WHICH OPACITY WAS DETERMINED Start STACK EXIT	End STACK EXIT
DESCRIBE PLUME BACKGROUND Start SKY & CLOUDS	End SKY & CLOUDS
BACKGROUND COLOR Start LT BLUE End LT BLUE	SKY CONDITIONS Start SCATTERED End SCATTERED
WIND SPEED Start 0-2 End 1-3	WIND DIRECTION (FROM) Start NNE End NNE
AMBIENT TEMP Start 82.0 End 83.9	WET BULB TEMP 77.5
RH, percent 76.1	

OBSERVATION DATE	START TIME	END TIME
6 MAY 2002	0811	0840

SEC / MIN	0	15	30	45	COMMENTS
1	0	0	0	0	
2	0	0	0	0	
3	0	0	0	0	
4	0	0	0	0	
5	0	0	0	0	
5	0	0	0	0	
7	0	0	0	0	
8	0	0	0	0	
9	0	0	0	0	
10	0	0	0	0	
11	0	0	0	0	
12	0	0	0	0	
13	0	0	0	0	
14	0	0	0	0	
15	0	0	0	0	
16	0	0	0	0	
17	0	0	0	0	
18	0	0	0	0	
19	0	0	0	0	
20	0	0	0	0	
21	0	0	0	0	
22	0	0	0	0	
23	0	0	0	0	
24	0	0	0	0	
25	0	0	0	0	
25	0	0	0	0	
27	0	0	0	0	
28	0	0	0	0	
29	0	0	0	0	
30	0	0	0	0	



ADDITIONAL INFORMATION

INCLINE = 15.2° HIGH SET ANG = 0

OBSERVER'S NAME (PRINT) JOHN GUISEPPI	
OBSERVER'S SIGNATURE	DATE 6 MAY 2002
ORGANIZATION CITY OF LAKELAND	
CERTIFIED BY EASTERN TECHNICAL ASSOCIATION	DATE 14 ~~MAY~~ FEB 2002 JPR
CONTINUED ON VEO FORM NUMBER	

VISIBLE EMISSION OBSERVATION FORM

No. 1/2

COMPANY NAME
CITY OF LAKELAND

STREET ADDRESS
3030 E. LAKE PARKER DR

UNIT 5 COMBUSTION TURBINE

CITY
LAKELAND

STATE
FL

ZIP
33805

PHONE (KEY CONTACT)
863 834 6600

SOURCE ID NUMBER
1050004 EUID 028

PROCESS EQUIPMENT
U5 COMBUSTION TURBINE

OPERATING MODE
POWER AUG

CONTROL EQUIPMENT
NONE

OPERATING MODE
N/A

DESCRIBE EMISSION POINT
STACK EXIT - TALL CONCRETE STACK

HEIGHT ABOVE GROUND LEVEL
≈300'

HEIGHT RELATIVE TO OBSERVER
Start ≈300' End ≈300'

DISTANCE FROM OBSERVER
Start ≈1000' End ≈1000'

DIRECTION FROM OBSERVER
Start EAST End EAST

DESCRIBE EMISSIONS
Start CT EXHAUST End CT EXHAUST

EMISSION COLOR
Start CLEAR End CLEAR

IF WATER DROPLET PLUME
Attached ☐ NONE Detached ☐

POINT IN THE PLUME AT WHICH OPACITY WAS DETERMINED
Start STACK EXIT End STACK EXIT

DESCRIBE PLUME BACKGROUND
Start SKY & CLOUDS End SKY & CLOUDS

BACKGROUND COLOR
Start BLU & WHT End BLU & WHT

SKY CONDITIONS
Start SCATTERED End SCATTERED

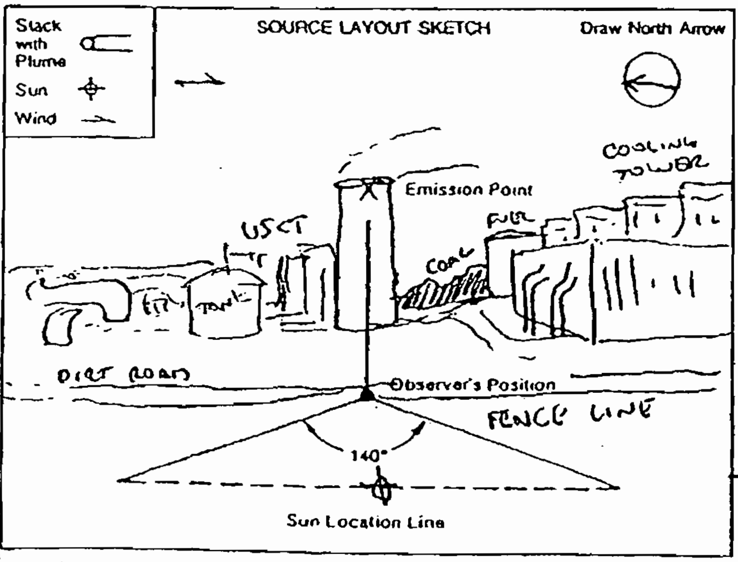
WIND SPEED
Start 3-5 End 3-5

WIND DIRECTION (FROM)
Start N End N

AMBIENT TEMP
Start 95.8 End 92.3

WET BULB TEMP
78.0

RH, percent
44.4%



ADDITIONAL INFORMATION
POWER AUGMENTATION IN SERVICE

INCLINE = 17.5° HIGH SET AVG ≈ 0

OBSERVATION DATE
6 MAY 2002

START TIME
13:01

END TIME
13:30

SEC / MIN	0	15	30	45	COMMENTS
1	0	0	0	0	
2	0	0	0	0	
3	0	0	0	0	
4	0	0	0	0	
5	0	0	0	0	
6	0	0	0	0	
7	0	0	0	0	
8	0	0	0	0	
9	0	0	0	0	
10	0	0	0	0	
11	0	0	0	0	
12	0	0	0	0	
13	0	0	0	0	
14	0	0	0	0	
15	0	0	0	0	
16	0	0	0	0	
17	0	0	0	0	
18	0	0	0	0	
19	0	0	0	0	
20	0	0	0	0	
21	0	0	0	0	
22	0	0	0	0	
23	0	0	0	0	
24	0	0	0	0	
25	0	0	0	0	
26	0	0	0	0	
27	0	0	0	0	
28	0	0	0	0	
29	0	0	0	0	
30	0	0	0	0	

OBSERVER'S NAME (PRINT)
JOHN GIUSEPPI

OBSERVER'S SIGNATURE

DATE
6 MAY 2002

ORGANIZATION
CITY OF LAKELAND

CERTIFIED BY
EASTERN TECHNICAL ASSOCIATION

DATE
14 FEB 02

CONTINUED ON VEO FORM NUMBER
2/2

VISIBLE EMISSION OBSERVATION FORM

No. 2/2

COMPANY NAME: CITY OF LAKELAND

STREET ADDRESS: 3030 E. LAKE PARKER DR

UNIT-5 COMBUSTION TURBINE

CITY: LAKELAND | STATE: FL | ZIP: 33805

PHONE (KEY CONTACT): 863 834 6600 | SOURCE ID NUMBER: 1050004 EUID 028

PROCESS EQUIPMENT: U5 COMBUSTION TURBINE | OPERATING MODE: Power Aug

CONTROL EQUIPMENT: NONE | OPERATING MODE: N/A

DESCRIBE EMISSION POINT: STACK EXIT - TALL CONCRETE STACK

HEIGHT ABOVE GROUND LEVEL: ≈ 300' | HEIGHT RELATIVE TO OBSERVER: Start ≈300' End ~300'

DISTANCE FROM OBSERVER: Start ≈1000' End ≈1000' | DIRECTION FROM OBSERVER: Start EAST End EAST

DESCRIBE EMISSIONS: Start CT EXHAUST End CT EXHAUST

EMISSION COLOR: Start CLEAR End CLEAR | IF WATER DROPLET PLUME: Attached ☐ NONE Detached ☐

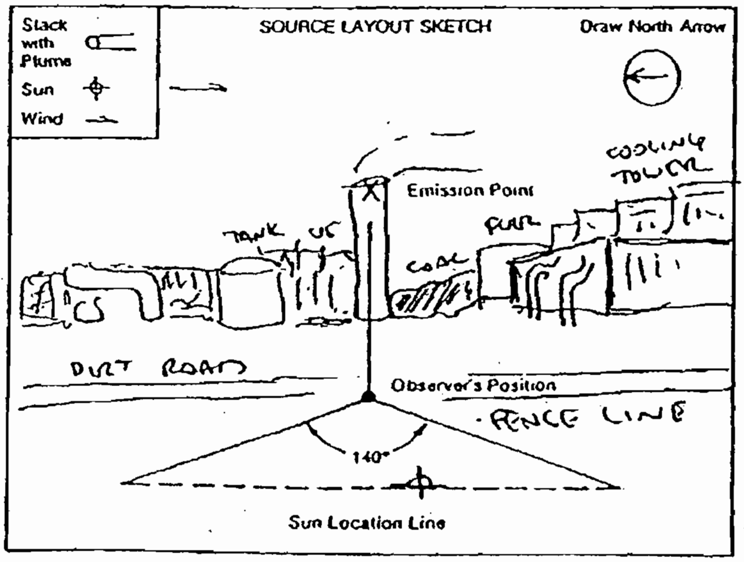
POINT IN THE PLUME AT WHICH OPACITY WAS DETERMINED: Start STACK EXIT End STACK EXIT

DESCRIBE PLUME BACKGROUND: Start SKY & CLOUDS End SKY & CLOUDS

BACKGROUND COLOR: Start BLU & WHT End BLU & WHT | SKY CONDITIONS: Start SCATTERED End SCATTERED

WIND SPEED: Start 3-5 End 3-5 | WIND DIRECTION (FROM): Start N End N

AMBIENT TEMP: Start 92.3 End 90.9 | WET BULB TEMP: 75.2 | RH, percent: 44.7



ADDITIONAL INFORMATION: POWER AUGMENTATION IN SERVICE

INCLINE ≈ 17.5' HIGH SET AUG = 0

OBSERVATION DATE: 6 MAY 2002 | START TIME: 13:31 | END TIME: 14:30

MIN \ SEC	0	15	30	45	COMMENTS
1	0	0	0	0	
2	0	0	0	0	
3	0	0	0	0	
4	0	0	0	0	
5	0	0	0	0	
6	0	0	0	0	
7	0	0	0	0	
8	0	0	0	0	
9	0	0	0	0	
10	0	0	0	0	
11	0	0	0	0	
12	0	0	0	0	
13	0	0	0	0	
14	0	0	0	0	
15	0	0	0	0	
16	0	0	0	0	
17	0	0	0	0	
18	0	0	0	0	
19	0	0	0	0	
20	0	0	0	0	
21	0	0	0	0	
22	0	0	0	0	
23	0	0	0	0	
24	0	0	0	0	
25	0	0	0	0	
26	0	0	0	0	
27	0	0	0	0	
28	0	0	0	0	
29	0	0	0	0	
30	0	0	0	0	

OBSERVER'S NAME (PRINT): JOHN GUISEPPI

OBSERVER'S SIGNATURE: | DATE: 6 MAY 2002

ORGANIZATION: CITY OF LAKELAND

CERTIFIED BY: EASTERN TECHNICAL ASSOCIATION | DATE: 14 FEB 02

CONTINUED ON VEO FORM NUMBER

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)

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

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

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

Mechanical Draft Cooling Tower

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

5. Emissions Unit Status Code: **A**	6. Initial Startup Date: **Jan 2002**	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [ ]

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

The mechanical draft cooling tower will reuse water with a maximum total dissolved solids content of up to 5,000 ppm when concentrated. A small portion of the water will be emitted as drift which will form particulate matter. The facility will have an insignificant increase in PM.

Emissions Unit Control Equipment

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

Mist Eliminator

2. Control Device or Method Code(s): **14**

Emissions Unit Details

1. Package Unit:
Manufacturer: Model Number:

2. Generator Nameplate Rating: 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:			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):			

Emissions Unit Information Section 7 of 8 **Mechanical Draft Cooling Tower**

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

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

Segment Description and Rate: Segment 1 of 1

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

Circulating Water Rate

2. Source Classification Code (SCC):

3. SCC Units:
1,000 gallons

4. Maximum Hourly Rate:
7,500

5. Maximum Annual Rate:
65,700,000

6. Estimated Annual Activity Factor:

7. Maximum % Sulfur:

8. Maximum % Ash:

9. Million Btu per SCC Unit:

10. Segment Comment (limit to 200 characters):

Segment Description and Rate: Segment _____ of _____

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

2. Source Classification Code (SCC):

3. SCC Units:

4. Maximum Hourly Rate:

5. Maximum Annual Rate:

6. Estimated Annual Activity Factor:

17. Maximum % Sulfur:

8. Maximum % Ash:

9. Million Btu per SCC Unit:

10. Segment Comment (limit to 200 characters):

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
PM	014		NS
PM_{10}	014		NS

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

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

Emissions Associated with Material Handling (Fugitive and Vent)

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

5. Emissions Unit Status Code: **A**	6. Initial Startup Date: **1 Sept 1982**	7. Emissions Unit Major Group SIC Code: **49**	8. Acid Rain Unit? [ ]

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

This emission unit information section addresses fugitive emissions and other emissions from material handling. The material handled include coal, petroleum coke, refuse, RDF, limestone, quick lime, fly ash, bottom ash, and FGD by-products.

Emissions Unit Control Equipment

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

   Water/Cyclones and Bag Filters Used to Control PM

2. Control Device or Method Code(s): **99**

Emissions Unit Details

1. Package Unit:
   Manufacturer: Model Number:
2. Generator Nameplate Rating: 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:				mmBtu/hr
2. Maximum Incineration Rate:		lb/hr		tons/day
3. Maximum Process or Throughput Rate:	**See Comment**			
4. Maximum Production Rate:	**See Comment**			
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):

Throughputs in TPY

1,398,121 Coal
269,455 Petcoke
132,334 Limestone
6,714 Lime
75,000 MSW/RDF
167,775 Fly Ash
41,944 Bottom Ash
429,185 FGD By-products
(From input/output of EU 3)

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

See Attachment MC-FI-C12	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? **See Attachment MC-EU7-J1**	2. Emission Point Type Code: **4**

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):

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

5. Discharge Type Code: **F**	6. Stack Height: feet	7. Exit Diameter: feet
8. Exit Temperature: °F	9. Actual Volumetric Flow Rate: acfm	10. Water Vapor: %

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

13. Emission Point UTM Coordinates:

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

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

Not Applicable.

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

Segment Description and Rate: Segment **1** of **8**

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

Coal

2. Source Classification Code (SCC): **A2530000040**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: **1,398,121**	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 EU 3.

Segment Description and Rate: Segment **2** of **8**

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

Petroleum Coke

2. Source Classification Code (SCC): **A2530000000**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: **269,455**	6. Estimated Annual Activity Factor:
18. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:

10. Segment Comment (limit to 200 characters):

Annual rate based on inputs to EU 3.

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

Segment Description and Rate: Segment 3 of 8

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Limestone**		
2. Source Classification Code (SCC): **A2530000100**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: **132,334**	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 EU 3.**		

Segment Description and Rate: Segment 4 of 8

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **MSW/RDF**		
2. Source Classification Code (SCC): **A2530000000**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: **75,000**	6. Estimated Annual Activity Factor:
19. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): **Annual rate based on inputs to EU 3.**		

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

Segment Description and Rate: Segment 5 of 8

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **Fly Ash**		
2. Source Classification Code (SCC): **A2530000000**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: **167,775**	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 output from EU 3.**		

Segment Description and Rate: Segment 6 of 8

1. Segment Description (Process/Fuel Type) (limit to 500 characters): **FGD By-product**		
2. Source Classification Code (SCC): **A2530000000**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: **429,185**	6. Estimated Annual Activity Factor:
20. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:
10. Segment Comment (limit to 200 characters): **Annual rate based on output from EU 3.**		

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

Segment Description and Rate: Segment 7 of 8

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

Lime

2. Source Classification Code (SCC): **A2530000000**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: **6,714**	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 requirements from EU 3.

Segment Description and Rate: Segment 8 of 8

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

Bottom Ash

2. Source Classification Code (SCC): **A2530000000**	3. SCC Units: **Tons**	
4. Maximum Hourly Rate:	5. Maximum Annual Rate: **41,944**	6. Estimated Annual Activity Factor:
21. Maximum % Sulfur:	8. Maximum % Ash:	9. Million Btu per SCC Unit:

10. Segment Comment (limit to 200 characters):

Annual rate based on output from EU 3.

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	099		WP
PM_{10}	099		NS

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

Visible Emissions Limitation: Visible Emissions Limitation 1 of 1

1. Visible Emissions Subtype:
VE20

2. Basis for Allowable Opacity:
[ ] Rule [ ] Other

3. Requested Allowable Opacity:
Normal Conditions: **20** % Exceptional Conditions: %
Maximum Period of Excess Opacity Allowed: min/hour

4. Method of Compliance:

None

5. Visible Emissions Comment (limit to 200 characters):

FDEP Rule 62-296.320(4)(b)1.

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

Continuous Monitoring System: Continuous Monitor ______ of ______

1. Parameter Code:

2. Pollutant(s):

3. CMS Requirement: [ ] Rule [ ] Other

4. Monitor Information:
Manufacturer:
Model Number: Serial Number:

5. Installation Date:

6. Performance Specification Test Date:

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

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

Supplemental Requirements

1. Process Flow Diagram
[X] Attached, Document ID: MC-EU8-J1 [ ] Not Applicable [ ] Waiver Requested

2. Fuel Analysis or Specification
[ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested

3. Detailed Description of Control Equipment
[X] Attached, Document ID: MC-EU8-J3 [ ] Not Applicable [ ] Waiver Requested

4. Description of Stack Sampling Facilities
[ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested

5. Compliance Test Report

[ ] Attached, Document ID: ________

[ ] Previously submitted, Date: ________

[X] Not Applicable

6. Procedures for Startup and Shutdown
[ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested

7. Operation and Maintenance Plan
[ ] Attached, Document ID: ________ [X] Not Applicable [ ] Waiver Requested

8. Supplemental Information for Construction Permit Application
[ ] Attached, Document ID: ________ [X] Not Applicable

9. Other Information Required by Rule or Statute
[ ] Attached, Document ID: ________ [X] Not Applicable

10. Supplemental Requirements Comment:

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation
[X] Attached, Document ID: MC-EU8-J11 [ ] 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: MC-FI-C12 [ ] 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:________

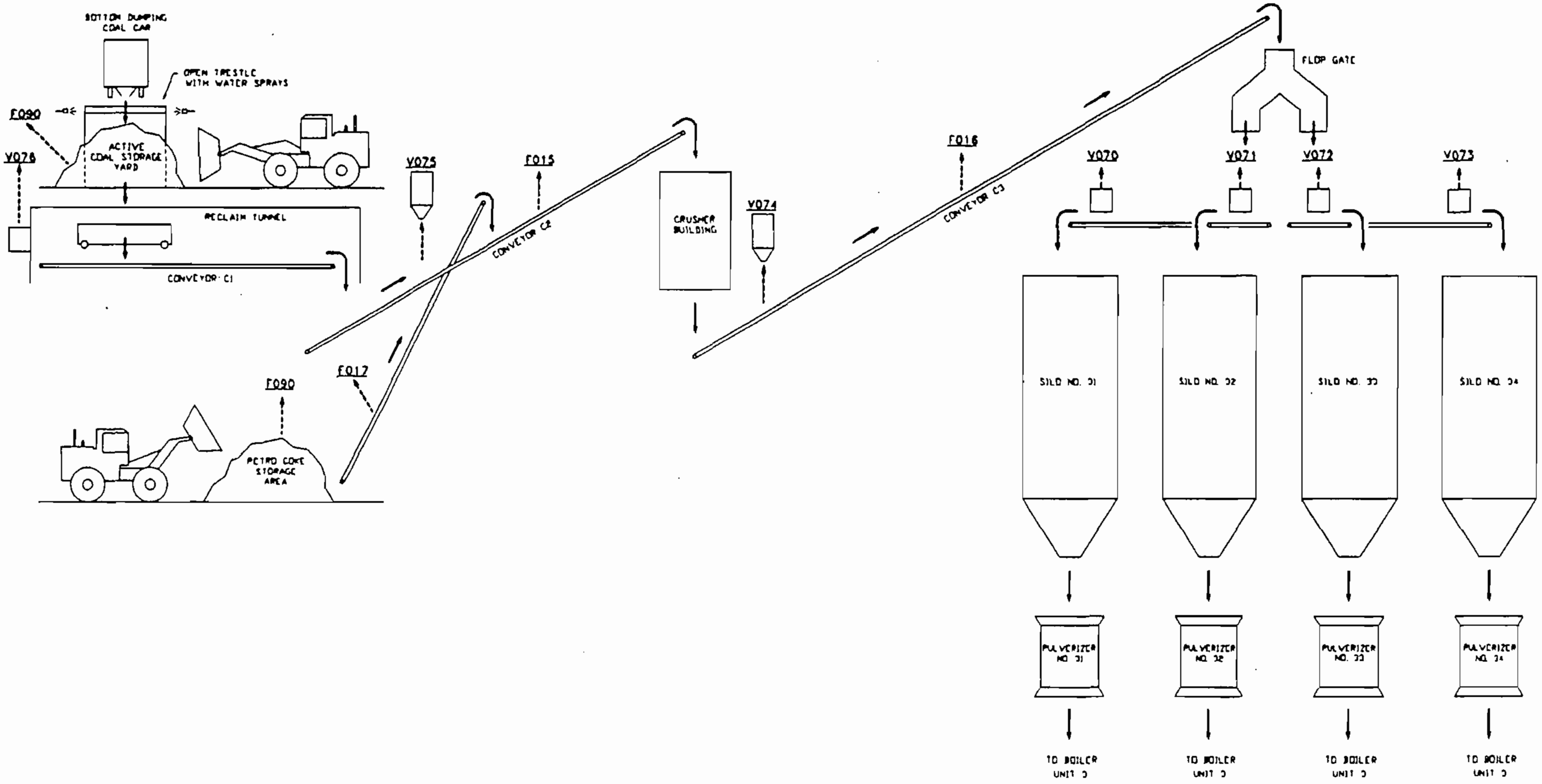
[ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.)
Attached, Document ID:________

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

[X] Not Applicable

ATTACHMENT MC-EU8-J1

PROCESS FLOW DIAGRAMS



0	MG	11-2-94		ISSUED FOR TITLE V PERMIT APPLICATION
1	MG	5-15-96	HP	CHANGE TITLE
2	MG	5-29-96	HP	ISSUED FOR TITLE V
REV. NO.	BY	DATE	APPR.	REVISION

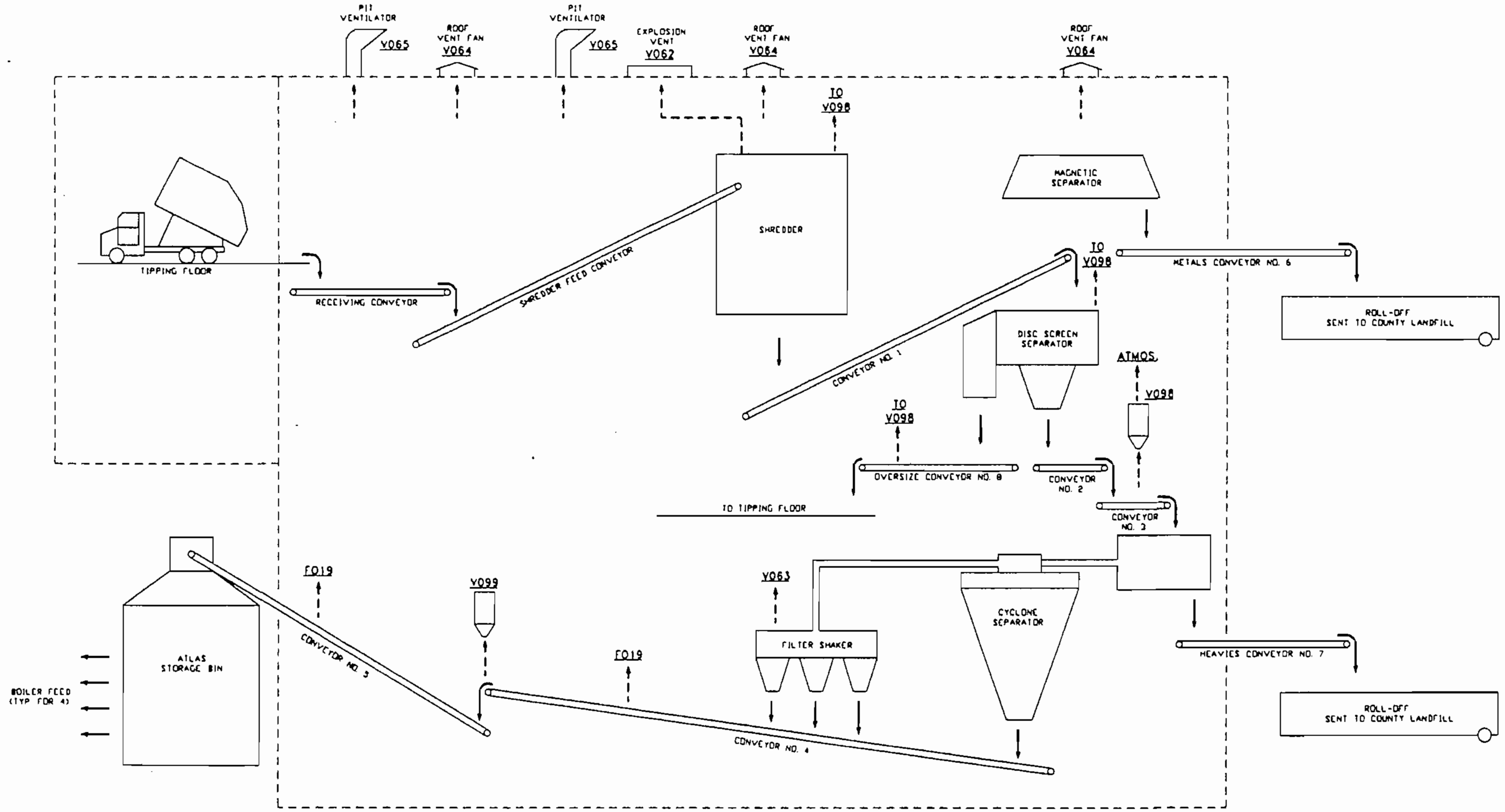
LAKELAND
ELECTRIC
& WATER

DESCRIPTION
LAKELAND ELECTRIC & WATER UTILITIES
C.D. McINTOSH POWER PLANT
COAL AND PETROCOKE STORAGE
AND HANDLING SYSTEM
PROCESS FLOW DIAGRAM

DIVISION PRODUCTION ENGINEERING
ENGINEER PATTERSON
DRN. BY: MGIEGER DATE 9-14-94
APPR. BY:

CAD SCALE NONE
PROJ. NO. AIR PERMIT
DWG. NO. LMC-EU6-L1/SKM-31
REV. 2

SIZE B



0	MG	11-2-94		ISSUED FOR TITLE V PERMIT APPLICATION
1	MG	5-15-96		CHANGE TITLE & V098
A	MG	X		FOR APPROVAL
REV NO.	BY	DATE	APPR.	REVISION

LAKELAND ELECTRIC & WATER

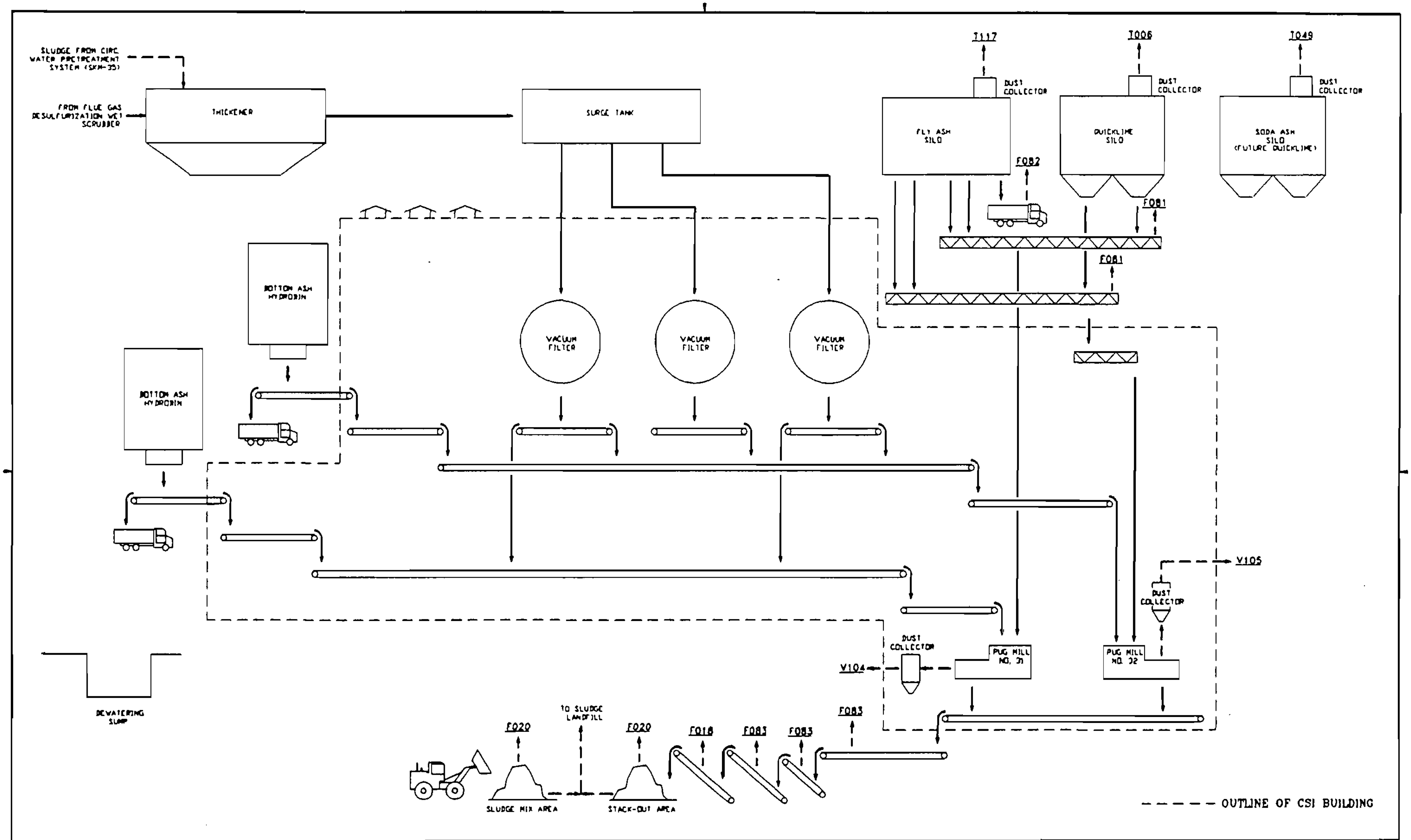
DESCRIPTION

LAKELAND ELECTRIC & WATER UTILITIES
C.D. McINTOSH POWER PLANT
REFUSE SYSTEM
PROCESS FLOW DIAGRAM

DIVISION PRODUCTION ENGINEERING
ENGINEER PATTERSON
DRN. BY: MGIEGER
DATE 9-14-94
APPR. BY:

CAD
SCALE NONE
PROJ. NO. AIR PERMIT
DWG. NO. LMC-EU6-L1/SKM-32
REV. 1

SIZE B



1	MG	8-9-95		ADDED SLUDGE MIX AREA AND F018
2	MG	5-14-96	HP	CHANGE TITLE
3	MG	5-29-96	HP	ISSUED FOR TITLE V
REV. NO.	BY	DATE	APPR.	REVISION

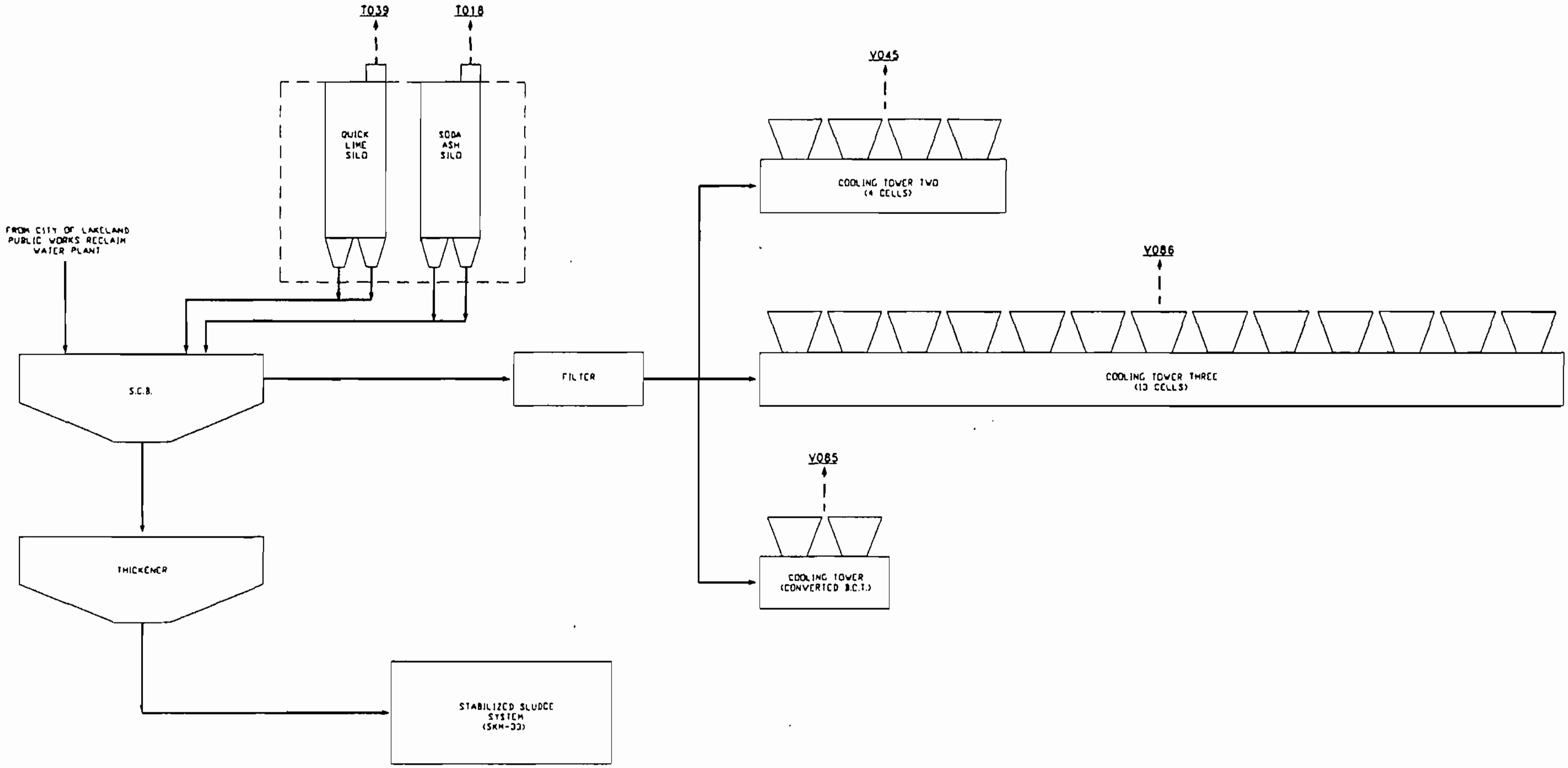
LAKELAND ELECTRIC & WATER

DESCRIPTION
LAKELAND ELECTRIC & WATER UTILITIES
C.D. McINTOSH POWER PLANT
STABILIZED SLUDGE SYSTEM
PROCESS FLOW DIAGRAM

DIVISION PRODUCTION ENGINEERING
ENGINEER PATTERSON
DRN. BY: MGIEGER
DATE 9-14-94
APPR. BY:

CAD
SCALE NONE
PROJ. NO. AIR PERMIT
DWG. NO. LMC-EU6-L1/SKM-33
REV. 3

SIZE B



REV. NO.	BY	DATE	APPR.	REVISION
0	MG	11-2-94		ISSUED FOR TITLE V PERMIT APPLICATION
1	MG	5-14-96	HP	CHANGE TITLE
A	MG	X		FOR APPROVAL

LAKELAND
ELECTRIC
& WATER

DESCRIPTION
LAKELAND ELECTRIC & WATER UTILITIES
C.D. McINTOSH POWER PLANT
CIRCULATING WATER
PRETREATMENT SYSTEM
PROCESS FLOW DIAGRAM

DIVISION PRODUCTION ENGINEERING
ENGINEER PATTERSON
DRN. BY: MGIEGER
DATE 9-23-94
APPR. BY:

CAD
SCALE NONE
PROJ. NO. AIR PERMIT
DWG. NO. LMC-EU6-L1/SKM-35
REV. 1

SIZE B

ATTACHMENT MC-EU8-J3

DESCRIPTION OF CONTROL EQUIPMENT

ATTACHMENT MC-EU8-J3

DETAILED DESCRIPTION OF CONTROL EQUIPMENT

The fugitive particulate matter emission sources associated with the material handling operations and their control is presented below (see also Attachment MC-EU8-J1):

Source Name	Location ID	Material	Control	Estimated Efficiency (%)
Trestle Dump	F090A	Coal	Dust Suppression	50+
Active Storage	F090B	Coal	Enclosure	50
Conveyor C1	V075	Coal	Bag Filter	98
Conveyor C2	F015	Coal	Enclosure	90
Crusher to C3	V016	Coal	Bag Filter	98
Conveyor C3 to Flop Gate	F016	Coal	Enclosure	90
Flop Gate to Silo Conveyors	V070-73	Coal	Bag Filter	98
Active Storage	F017a	Pet Coke	Watering	50+
Pet Coke to Hopper	F017b	Pet Coke	Watering	50+
Truck Dump	F094	Limestone	Enclosure	50
Vertical Conveyor to Silo	T001	Limestone	Bag Filter	98
Silo to Conveyor	F022a	Limestone	Enclosure	90
Conveyor to Ball Mill	F022b	Limestone	Enclosure	90
Ball Mill to FGD Slurry Tank	F080	Limestone	Enclosure	90
Crusher	V074	Coal	Bag Filter	98
Truck Dump	V065	MSW	Partial Enclosure	50

Source Name	Location ID	Material	Control	Estimated Efficiency (%)
Conveyor No. 3 Vent	V098	RDF	Bag Filter	98
Shredder Cyclone	V061	MSW/RDF	Cyclone	90+
Explosive Vent	V062	MSW/RDF	Enclosure	90
Filter Shaker Vent	V063	RDF	Bag Filter	98
Conveyor No. 4	F019A	RDF	Enclosure	90
Conveyor No. 4 Vent	V099	RDF	Bag Filter	98
Conveyor No. 5 & Atlas Bin	F019B	RDF	Enclosure	90
Fly Ash to Silo	T117	Fly Ash	Bag Filter	98
Fly Ash Silo to Tanker Truck	F082	Fly Ash	Bag Filter	98
Fly Ash/Quick Lime Conveying	F081	Fly Ash and Quick Lime	Enclosure	90
Pug Mill No. 31	V104	Fly Ash/Quick Lime/FGD Sludge	Moisture and Enclosure	98
Pug Mill No. 32	V105	Fly Ash/Quick Lime/FGD Sludge	Moisture and Enclosure	98
Stabilized FGD Conveying	F083	FGD By-product	None Required	NA
Quick Lime Silo	T006	Lime	Bag Filter	98
Truck Dump at Landfill	F091	FGD By-product	Watering	50+

MSW = muncipal solid waste; RDF = refuse derived fuel; FGD = flue gas desulfurization

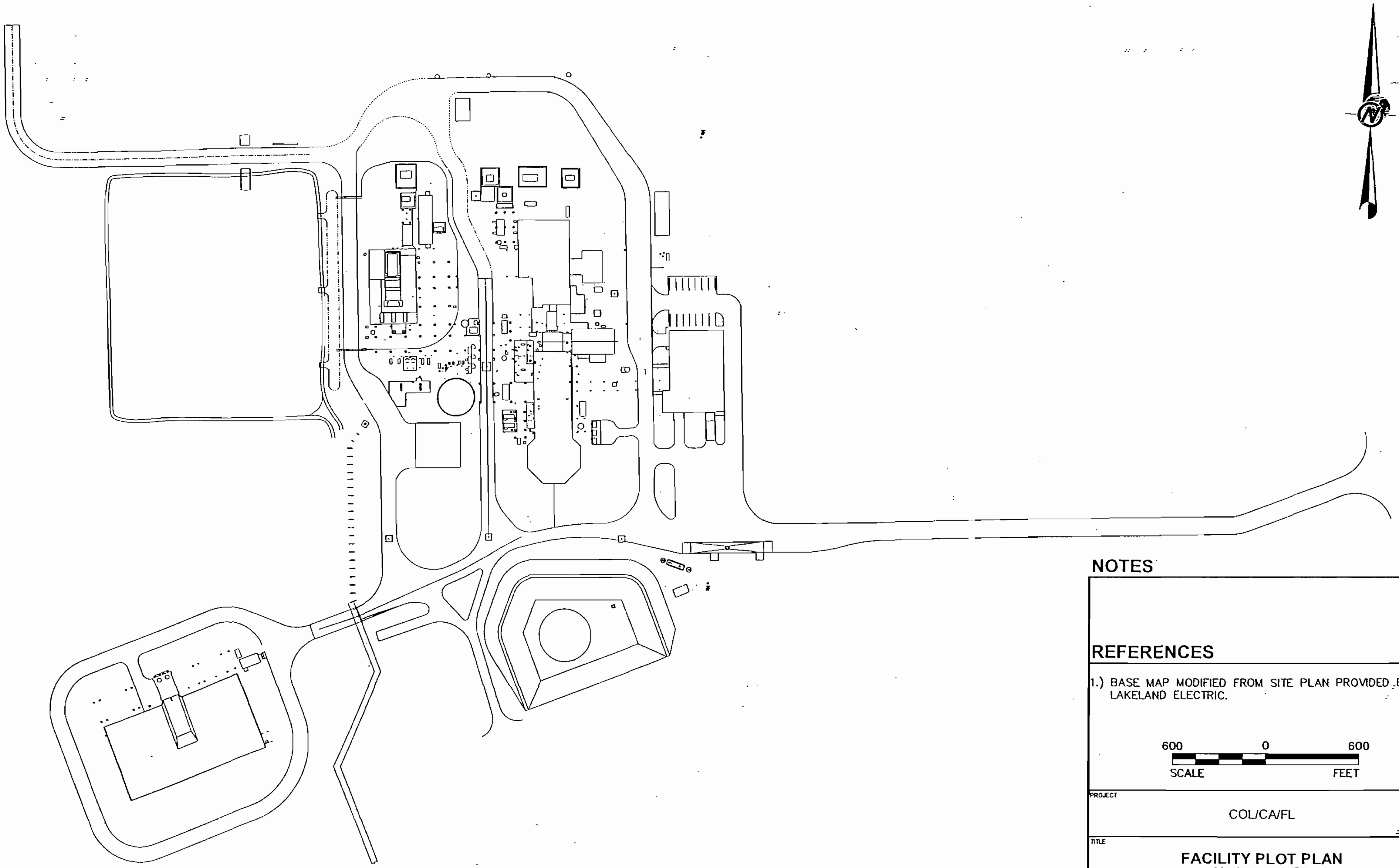
ATTACHMENT MC-EU8-J11

ALTERNATIVE METHODS OF OPERATION

ATTACHMENT MC-EU8-J11

ALTERNATIVE METHODS OF OPERATION

The coal handling facilities can operate on any type of coal and petroleum coke. Capacities included in the application are based on the maximum production rates for Emission Unit 3. Material handling facilities have greater capacities and can be operated in various ways as presented in the process flow diagrams. All materials are processed at different hourly and annual rates.



NOTES

REFERENCES

1.) BASE MAP MODIFIED FROM SITE PLAN PROVIDED BY LAKELAND ELECTRIC.

600 0 600

SCALE FEET

PROJECT

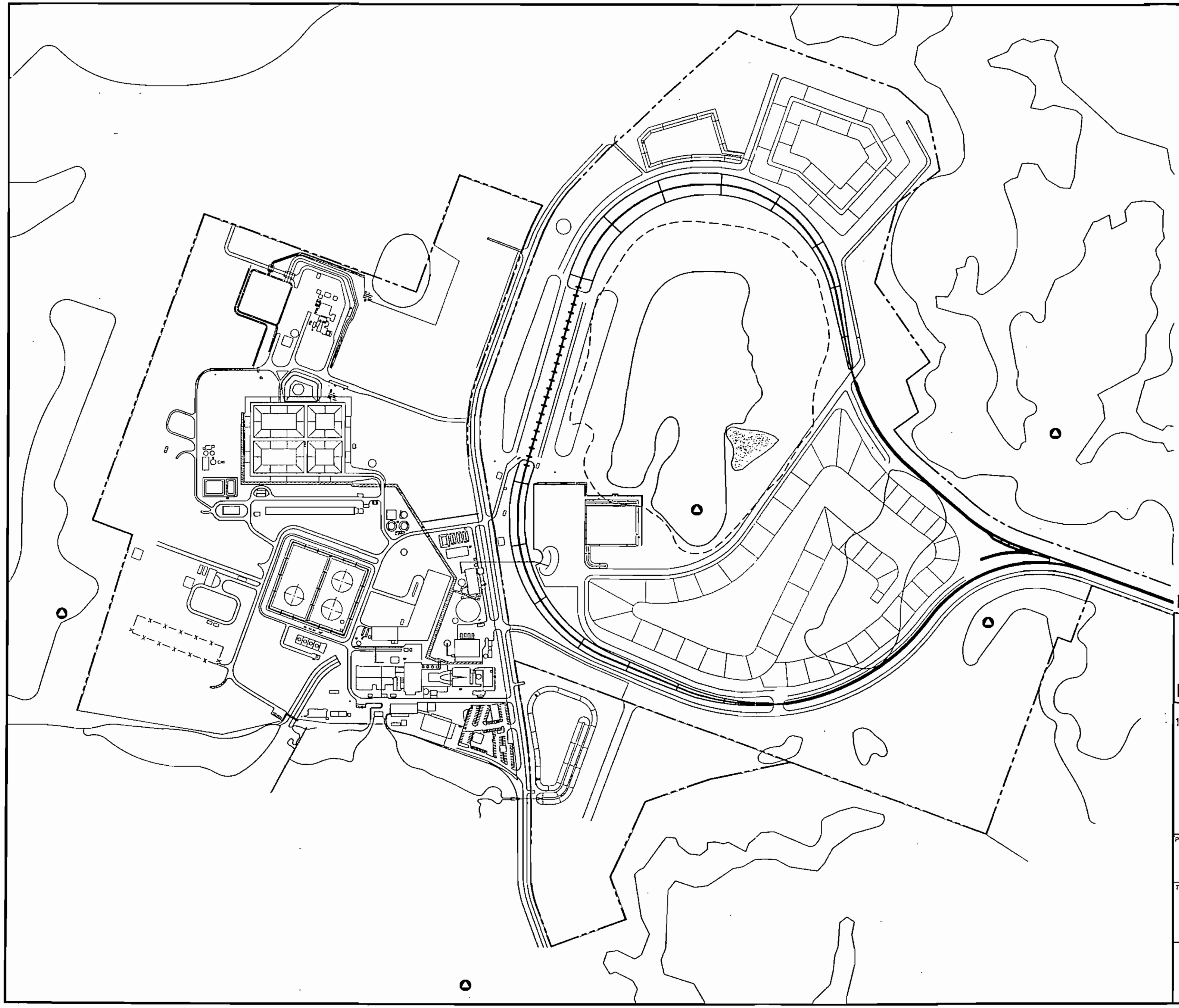
COL/CA/FL

TITLE

FACILITY PLOT PLAN
UNIT 5 AREA

Golder Associates
Gainesville, Florida

PROJECT No.		013–7674	FILE No.	7674V1
DESIGN			SCALE AS SHOWN	REV. 0
CADD	GMS	3/25/03	4	
CHECK				
REVIEW				



NOTES

REFERENCES

1.) BASE MAP MODIFIED FROM SITE PLAN PROVIDED BY LAKELAND ELECTRIC.

600 0 600

SCALE FEET

PROJECT

COL/CA/FL

TITLE

FACILITY PLOT PLAN

Golder Associates
Gainesville, Florida

PROJECT No.		013-7674	FILE No.	7674V1
DESIGN			SCALE AS SHOWN	REV. 0
CADD	GMS	3/25/03	4	
CHECK				
REVIEW				