Kissimmee Utility Authority

Cane Island Power Park

Initial Air Operation Permit Application
Chapter 62-213 Title V Source

June 1996

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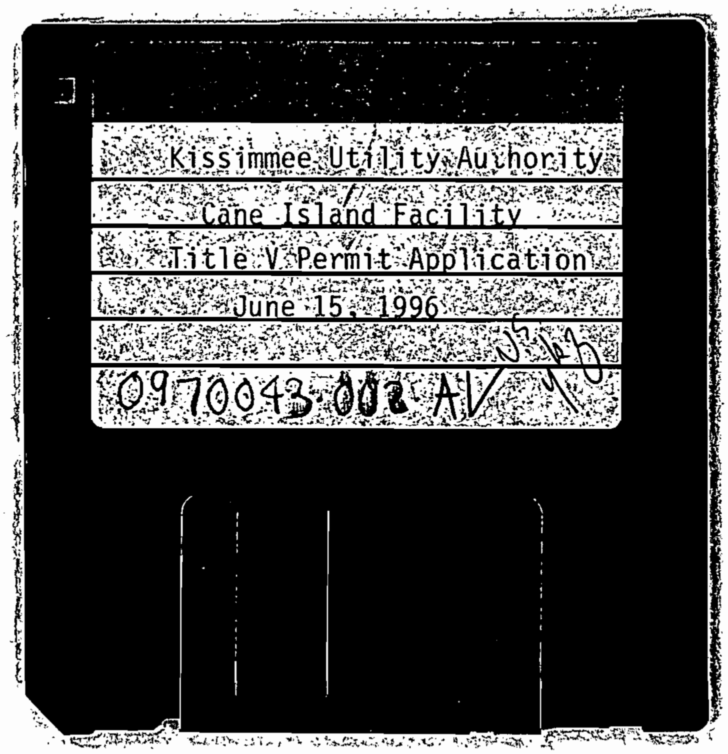
Kissimmee Utility Authority
Cane Island Facility
Title V Permit Application
June 15, 1996
0970043-002 AV

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I. Application Information

Department of
Environmental Protection

DIVISION OF AIR RESOURCES MANAGEMENT

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Identification of Facility Addressed in This Application

1. Facility Owner/Company Name : Kissimmee Utility Authority	
2. Site Name : Cane Island Power Park	
3. Facility Identification Number : 30ORL490043	[ ] Unknown
4. Facility Location : Kissimmee Utility Authority (KUA) Cane Island Power Park Located 10 km west of Kissimmee, near Intercession City, Osceola County, Florida Street Address or Other Locator : 6075 Old Tampa Hwy City : Intercession City County : Osceola Zip Code : 33848	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official : Name : A. K. Sharma Title : Director of Power Supply
2. Owner or Authorized Representative or Responsible Official Mailing Address : Organization/Firm : Kissimmee Utility Authority Street Address : 1701 West Carroll Street City : Kissimmee State : FL Zip Code : 34741-6804
3. Owner/Authorized Representative or Responsible Official Telephone Numbers : Telephone : (407)933-7777 Fax : (407)847-0787
4. Owner/Authorized Representative or Responsible Official Statement : *I, the undersigned, am the owner or authorized representative* of the non-Title V source addressed in this Application for Air Permit or the responsible official, as defined in Rule 62-210.200, F.A.C., 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 units.* AK Sharma   6/13/96 Signature   Date

* Attach letter of authorization if not currently on file.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type
001	Unit 1 - 40 MW Simple Cycle Combustion Turbine	NA
002	Unit 2 - 120 MW Combined Cycle Combustion Turbine	NA
003	Distillate Fuel Oil Storage Tank (300,000 gal) No. 1	NA
004	Distillate Fuel Oil Storage Tank (700,000 gal) No. 2	NA

Purpose of Application and Category

Category I : All Air Operation Permit Applications Subject to Processing Under Chapter 62-213, F.A.C.

This Application for Air Permit is submitted to obtain :

[X] Initial air operation permit under Chapter 62-213, F.A.C., for an existing facility which is classified as a Title V source.

[ ] Initial air operation permit under Chapter 62-213, F.A.C., 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 :

[ ] Air operation permit renewal under Chapter 62-213, F.A.C., for a Title V source.

Operation permit to be renewed :

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

Current construction permit number :

Operation permit to be revised :

[ ] Air operation permit revision or administrative correction for a Title V source to address one or more proposed new or modified emissions units and to be processed concurrently with the air construction permit application.

Operation permit to be revised/corrected :

[ ] Air operation permit revision for a Title V source for reasons other than construction or

modification of an emissions unit.

Operation permit to be revised :

Reason for revision :

Category II : All Air Operation Permit Applications Subject to Processing Under Rule 62-210.300(2)(b), F.A.C.

This Application for Air Permit is submitted to obtain :

[ ] Initial air operation permit under Rule 62-210.300(2)(b), F.A.C., for an existing facility seeking classification as a synthetic non-Title V source.

Current operation/construction permit number(s) :

[ ] Renewal air operation permit under Fule 62-210.300(2)(b), F.A.C., for a synthetic non-Title V source.

Operation permit to be renewed :

[ ] Air operation permit revision for a synthetic non-Title V source.

Operation permit to be revised :

Reason for revision :

Category III : All Air Construction Permit Applications for All Facilities and Emissions Units

This Application for Air Permit is submitted to obtain :

[ ] Air construction permit to construct or modify one or more emissions units within a facility (including any facility classified as a Title V source).

Current operation permit number(s), if any :

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

Current operation permit number(s) :

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

Application Processing Fee

Check one :

[ ] Attached - Amount : ____________ [X] Not Applicable.

Construction/Modification Information

1. Description of Proposed Project or Alterations : Not applicable
2. Projected or Actual Date of Commencement of Construction :
3. Projected Date of Completion of Construction :

Professional Engineer Certification

1. Professional Engineer Name : D.D. Schultz Registration Number : 30304
2. Professional Engineer Mailing Address : Organization/Firm : Black & Veatch Street Address : 8400 Ward Parkway City : Kansas City State : MO Zip Code : 64114-2031
3. Professional Engineer Telephone Numbers : Telephone : (913)339-2028 Fax : (913)339-2934

4. Professional Engineer Statement :

I, the undersigned, hereby certified, 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 pollutant 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 permi revision for one or more newly constructed or modified emissions units (check here [ ] if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions 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.

D. O. Schultz
Signature

6/12/96
Date

* Attach any exception to certification statement.

Application Contact

1. Name and Title of Application Contact :	
Name :	A. K. Sharma
Title :	Director of Power Supply
2. Application Contact Mailing Address :	
Organization/Firm :	Kissimmee Utility Authority
Street Address :	1701 West Carrol Street
City :	Kissimmee
State :	FL Zip Code : 34741-6804
3. Application Contact Telephone Numbers :	
Telephone :	(407)933-7777 Fax : (407)847-0787

Application Comment

Initial operating permit application for the facility. Facility currently operating in accordance with a construction permit until November 1, 1996 (or 240 days after commencing operation) pursuant to F.A.C. Rule 62-213.420 (1) (a) 4. The applicability of this rule is verified in an FDEP letter issued to KUA on October 11, 1995.

II. Facility Information

A. General Facility Information

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility, Location, and Type

1. Facility UTM Coordinates : Zone : 17 East (km) : 447.72 North (km) : 3127.68			
2. Facility Latitude/Longitude : Latitude (DD/MM/SS) : Longitude (DD/MM/SS) :			
3. Governmental Facility Code : 0	4. Facility Status Code : A	5. Facility Major Group SIC Code : 49	6. Facility SIC(s) :
7. Facility Comment :			

Facility Contact

1. Name and Title of Facility Contact : Jeff Ling Plant Manager
2. Facility Contact Mailing Address : Organization/Firm : KUA Cane Island Power Plant Street Address : 6075 Old Tampa Hwy City : Intercession City State : FL Zip Code : 33848-9999
3. Facility Contact Telephone Numbers : Telephone : (407)846-7070 Fax : (407)846-6485

Facility Regulatory Classifications

1. Small Business Stationary Source?	N
2. Title V Source?	Y
3. Synthetic Non-Title V Source?	N
4. Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	Y
5. Synthetic Minor Source of Pollutants Other than HAPs?	N
6. Major Source of Hazardous Air Pollutants (HAPs)?	Y
7. Synthetic Minor Source of HAPs?	N
8. One or More Emissions Units Subject to NSPS?	Y
9. One or More Emission Units Subject to NESHAP?	N
10. Title V Source by EPA Designation?	N
11. Facility Regulatory Classifications Comment : Facility units currently exempt under NESHAPs. The cooling tower is not subject to a NESHAP because chromium-based chemical treatment is not used. Therefore, the cooling tower is not a major source of HAPs.	

B.Facility Regulations

B. FACILITY REGULATIONS

Rule Applicability Analysis

N/A - Facility is a Title V source

B. FACILITY REGULATIONS

List of Applicable Regulations

FDEP Title V Core List (effective 3/25/95) incorporated by reference

40 CFR Part 60, Subpart A - Standards of Performance for New Stationary Sources

40 CFR part, 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid

40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines

40 CFR Part 61, Subpart A - National Emission Standards for Hazardous Air Pollutants (NESHAP)

40 CFR Part 61, Subpart M - National Emission Standard for Asbestos

Part 70 - State Operating Permit Programs

Section 70.1 - Program Overview

Section 70.2 - Definitions

Section 70.3 - Applicability

Section 70.4 - State Program Submittals and Transition

Section 70.5 - Permit Applications

Section 70.6 - Permit Content

Section 70.7 - Permit Issuance, Renewal, Reopenings, and Revisions

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 72.11 - Computation of Time

Section 72.12 - Administrative Appeals

Section 72.13 - Incorporation by Reference

Subpart B - Designated Representative

Section 72.20 - Authorization and Responsibilities of the Designated

Section 72.21 - Submissions

Section 72.22 - Alternate Designated Representative

Section 72.23 - Changing the Designated Representative, Alternate Designated

Section 72.24 - Certificate of Representation

Section 72.25 - Objections

Subpart C - Acid Rain Application

Section 72.30 - Requirements to Apply

Section 72.31 - Information Requirements for Acid Rain Permit

Section 72.32 - Permit Application Shield and Binding Effect of Permit

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 70.8 - Permit Review by the EPA and Affected States

Section 70.9 - Fee Determination and Certification

Section 70.10 - Federal Oversight and Sanctions

Section 70.11 - Requirements for Enforcement Authority

Part 72 - Regulations on Permits

Subpart A - Acid Rain Program General Provisions

Section 72.1 - Purpose and Scope

Section 72.2 - Definitions

Section 72.3 - Measurements, Abbreviations, and Acronyms

Section 72.4 - Federal Authority

Section 72.5 - State Authority

Section 72.6 - Applicability

Section 72.9 - Standard Requirements

Section 72.10 - Availability of Information

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 72.33 - Identification of Dispatch System

Subpart D - Acid Rain Compliance Plan and Compliance Options

Section 72.40 - General

Subpart E - Acid Rain Permit Contents

Section 72.50 - General

Section 72.51 - Permit Shield

Subpart F - Federal Acid Rain Permit Issuance Procedure

Section 72.60 - General

Section 72.61 - Completeness

Section 72.62 - Draft Permit

Section 72.63 - Administrative Record

Section 72.64 - Statement of Basis

Section 72.65 - Public Notice of Opportunities for Public Comment

Section 72.66 - Public Comments

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 72.67 - Opportunity for Public Hearing

Section 72.68 - Response to Comments

Section 72.69 - Issuance and Effective Date of Acid Rain Permits

Subpart G - Acid Rain Phase II Implementation

Section 72.70 - Relationship to Title V Operating Permit Program

Section 72.71 - Approval of State Programs--General

Section 72.72 - State Permit Program Approval Criteria

Section 72.73 - State Issuance of Phase II Permits

Section 72.74 - Federal Issuance of Phase II Permits

Subpart H - Permit Revisions

Section 72.80 - General

Section 72.81 - Permit Modifications

Section 72.82 - Fast-Track Modifications

Section 72.83 - Administrative Permit Amendment

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 72.84 - Automatic Permit Amendment

Section 72.85 - Permit Reopenings

Subpart I - Compliance Certification

Section 72.90 - Annual Compliance Certification Report

Section 72.95 - Allowance Deduction Formula

Section 72.96 - Administrator's Action on Compliance Certifications

Part 73 - Sulfur Dioxide Allowance Systems

Subpart A - Background and Summary

Section 73.1 - Purpose and Scope

Section 73.2 - Applicability

Section 73.3 - General

Subpart B - Allowance Allocations

Section 73.10 - Initial Allocations for Phase I and II

Section 73.11 - Revision of Allocations

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 73.12 - Rounding Procedures

Section 73.13 - Procedures for Submittals

Section 73.26 - Conservation and Renewable Energy Reserve

Section 73.27 - Special Allowance Reserve

Subpart C - Allowance Tracking System

Section 73.30 - Allowance Tracking System Accounts

Section 73.31 - Establishment of Accounts

Section 73.32 - Allowance Account Contents

Section 73.33 - Authorized Account Representative

Section 73.34 - Recordation in Accounts

Section 73.35 - Compliance

Section 73.36 - Banking

Section 73.37 - Account Error and Dispute Resolution

Section 73.38 - Closing of Accounts

B. FACILITY REGULATIONS

List of Applicable Regulations

Subpart D - Allowance Transfers

Section 73.50 - Scope and Submission of Transfers

Section 73.51 - Prohibition

Section 73.52 - EPA Recordation

Section 73.53 - Notification

Subpart E - Auctions, Direct Sales, and Independent Power Producers Written

Section 73.70 - Auctions

Section 73.71 - Bidding

Section 73.72 - Direct Sales

Section 73.73 - Delegation of Auctions and Sales and Termination of Auctions

Section 73.74 - Independent Power Producers Written Guarantee

Section 73.75 - Application for an IPP Written Guarantee

Section 73.76 - Approval and Exercise of the IPP Written Guarantee

Section 73.77 - Relationship of Independent Power Producers Written Guarantee

B. FACILITY REGULATIONS

List of Applicable Regulations

Subpart F - Energy Conservation and Renewable Energy Reserve

Section 73.80 - Operation of Allowance Reserve Program for Conservation and

Section 73.81 - Qualified Conservation Measures and Renewable Energy

Section 73.82 - Application for Allowances from Reserve Program

Section 73.83 - Secretary of Energy's Action on Net Income Neutrality

Section 73.84 - Administrator's Action on Applications

Section 73.85 - Administrator Review of the Reserve Program

Section 73.86 - State Regulatory Autonomy, Appendix A to Subpart F--List of

Part 75 - Emission Monitoring

Subpart A - General

Section 75.1 - Purpose and Scope

Section 75.2 - Applicability

Section 75.3 - General Acid Rain Program Provisions

Section 75.4 - Compliance Dates

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 75.5 - Prohibitions

Section 75.6 - Incorporation by Reference

Section 76.7 - EPA Study

Section 76.8 - [Reserved]

Subpart B - Monitoring Provisions

Section 75.10 - General Operating Requirements

Section 75.11 - Specific Provisions for Monitoring SO2 Emissions (SO2 and flow

Section 75.12 - Specific Provisions for Monitoring NOx Emissions (NOx and

Section 75.13 - Specific Provisions for Monitoring CO2 Emissions

Section 75.14 - Specific Provisions for Monitoring Opacity

Section 75.15 - Specific Provisions for Monitoring SO2 Emissions Removal by

Section 75.16 - Specific Provisions for Monitoring Emissions from Common, By-

Section 75.17 - Specific Provisions for Monitoring Emissions from Common, By-

Section 75.18 - Specific Provisions for Monitoring Emissions from Common and

B. FACILITY REGULATIONS

List of Applicable Regulations

Subpart C - Operation and Maintenance Requirements

Section 75.20 - Certification and Recertification Procedures

Section 75.21 - Quality Assurance and Quality Control Requirements

Section 75.22 - Reference Test Methods

Section 75.23 - Alternatives to ASTM Methods

Section 75.24 - Out-of-Control Periods

Subpart D - Missing Data Substitution Procedures

Section 75.30 - General Procedures

Section 75.31 - Initial Missing Data Procedures

Section 75.32 - Determinations of Monitor Data Availability for Standard Missing

Section 75.33 - Standard Missing Data Procedures

Section 75.34 - Units with Add-On Emission Controls

Subpart E - Alternative Monitoring Systems

Section 75.40 - General Demonstration Requirements

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 75.41 - Precision Criteria

Section 75.42 - Reliability Criteria

Section 75.43 - Accessibility Criteria

Section 75.44 - Timelines Criteria

Section 75.45 - Daily Quality Assurance Criteria

Section 75.46 - Missing Data Substitution Criteria

Section 75.47 - Criteria for a Class of Affected Units

Section 75.48 - Petition for an Alternative Monitoring System

Subpart F - Recordkeeping Requirements

Section 75.50 - General Recordkeeping Provisions

Section 75.51 - General Recordkeeping Provisions for Specific Situations

Section 75.52 - Certification, Quality Assurance and Quality Control Record

Section 75.53 - Monitoring Plan

Subpart G - Reporting Requirements

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 75.60 - General Provisions

Section 75.61 - Notification of Certification and Recertification Test Dates

Section 75.62 - Monitoring Plan

Section 75.63 - Certification or Recertification Applications

Section 75.64 - Quarterly Reports

Section 75.65 - Opacity Reports

Section 75.66 - Petitions to the Administrator

Section 75.67 - Retired Units Petitions

Part 76 - EPA Regulations on Acid Rain Nitrogen Oxides

Section 76.1 - Applicability

Section 76.2 - Definitions

Section 76.3 - General Acid Rain Program Provisions

Section 76.4 - Incorporation by Reference

Section 76.5 - Nox Emission Limitations for Group 1 Boilers

B. FACILITY REGULATIONS

List of Applicable Regulations

Section 76.6 - NOx Emission Limitations for Group 2 Boilers [Reserved]

Section 76.7 - Revised NOx Emission Limitations for Group 1, Phase II Boilers

Section 76.8 - Early Election for Group 1, Phase II Boilers

Section 76.9 - Permit Application and Compliance Plans

Section 76.10 - Alternative Emission Limitations

Section 76.11 - Emissions Averaging

Section 76.12 - Phase I NOx Compliance Extensions

Section 76.13 - Compliance and Excess Emissions

Section 76.14 - Monitoring, Recordkeeping, and Reporting

Section 76.15 - Test Methods and Procedures

Section 76.16 - [Reserved]

Part 77 - Excess Emissions

State Applicable Requirements

Chapter 62-4, F.A.C.; PERMITS

B. FACILITY REGULATIONS

List of Applicable Regulations

62-4.055 - Permit Processing

Chapter 62-210, F.A.C.; STATIONARY SOURCES - GENERAL REQUIREMENTS

62-210.550 - Stack Height Policy

62-210.700 - Excess Emissions

Chapter 62-212, F.A.C.; STATIONARY SOURCES - PRECONSTRUCTION REVIEW

62-212.300 - General Preconstruction Review Requirements

62-212.400 - Prevention of Significant Deterioration

62-212.410 - Best Available Control Technology

Chapter 62-213, F.A.C.; OPERATION PERMITS FOR MAJOR SOURCES OF AIR POLLUTION

62-213.413 - Fast-Track Revisions of Acid Rain Parts

Chapter 62-214, F.A.C.; REQUIREMENTS FOR SOURCES SUBJECT TO THE FEDERAL ACID RAIN P

62-214.300 - Applicability

62-214.320 - Applications

62-214.330 - Acid Rain Compliance Plan and Compliance Options

B. FACILITY REGULATIONS

List of Applicable Regulations

62-214.350 - Certification

62-214.370 - Revisions and Administrative Corrections

62-214.420 - Acid Rain Part Content

62-214.430 - Implementation and Termination of Compliance Options

Chapter 62-272, F.A.C.; AMBIENT AIR QUALITY STANDARDS

62-272.500 - Maximum Allowable Increases

Chapter 62-273, F.A.C.; AIR POLLUTION EPISODES

62-273.300 - Air Pollution Episodes

62-273.400 - Air Alert

62-273.500 - Air Warning

62-273.600 - Air Emergency

Chapter 62-296, F.A.C.; STATIONARY SOURCES - EMISSION STANDARDS

62-296.405 - Fossil Fuel Steam Generators

Chapter 62-297, F.A.C.; STATIONARY SOURCES - EMISSIONS MONITORING

B. FACILITY REGULATIONS

List of Applicable Regulations

62-297.401 - Compliance Test Methods

62-297.440 - Supplementary Test Procedures

62-297.520 - EPA Performance Specifications

62-297.620 - Exceptions and Approval of Alternate Procedures and Requirements

62-297.310, General Test Requirements

C.Facility Pollutants

C. FACILITY POLLUTANTS

Facility Pollutant Information

1. Pollutant Emitted	2. Pollutant Classification
VOC	A
CO	A
NOX	A
PM	A
PM10	A
SO2	A
PB	B
H095	A
H021	B
H015	B
H114	B

D.Facility Pollutant Detail Information

E.Facility Supplemental Information

D. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements for All Applications

1. Area Map Showing Facility Location :	Appendix A
2. Facility Plot Plan :	Appendix B
3. Process Flow Diagram(s) :	Appendix C
4. Precautions to Prevent Emissions of Unconfined Particulate Matter :	Appendix D
5. Fugitive Emissions Identification :	Appendix E
6. Supplemental Information for Construction Permit Application :	NA

Additional Supplemental Requirements for Category I Applications Only

7. List of Proposed Exempt Activities :	Appendix F
8. List of Equipment/Activities Regulated under Title VI :	Appendix G
9. Alternative Methods of Operation :	Appendix H
10. Alternative Modes of Operation (Emissions Trading) :	NA
11. Identification of Additional Applicable Requirements :	Appendix I
12. Compliance Assurance Monitoring Plan :	Appendix J
13. Risk Management Plan Verification :	Appendix K
14. Compliance Report and Plan :	Appendix L
15. Compliance Certification (Hard-copy Required) :	Appendix M

III. Emissions Unit Information

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

<u>Type of Emissions Unit Addressed in This Section</u>

1. 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.

2. Single Process, Group of Processes, or Fugitive Only? 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.

Emissions Unit Information Section 1

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Unit 1 - 40 MW Simple Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 001 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : A	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : Natural gas or low sulfur distillate fuel oil fired. Unit information throughout application is based on baseload, ISO conditions, commensurate with ATC permit AC49-205703		

Emissions Unit Control Equipment 1

1. Description :	
	Water Injection: Used to limit NOx emissions by lowering the combustion temperature through the use of water injection. This will be used for natural gas and fuel oil firing.
2. Control Device or Method Code :	28

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Emissions Unit Control Equipment 2

1. Description : Use of low sulfur fuel oil (0.05 percent) and the use of natural gas to control emissions of SO2.
2. Control Device or Method Code : 30

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date :	23-Aug-1994	
2. Long-term Reserve Shutdown Date :		
3. Package Unit : Manufacturer : General Electric		Model Number : LM-6000
4. Generator Nameplate Rating :	40 MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :		 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate :	367 mmBtu/hr	
2. Maximum Incinerator Rate :	lb/hr	tons/day
3. Maximum Process or Throughput Rate :		
4. Maximum Production Rate :		
5. Operating Capacity Comment : The maximum heat input in field 1 is based on natural gas firing (LHV) at ISO conditions (base load). The max heat input for No. 2 distillate fuel oil firing is 371 MBtu/hour (LHV) at ISO conditions (baseload). The corresponding HHV are 407 MBtu/hour (gas) and 397 MBtu/hour (oil).		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule :		
	24 hours/day	7 days/week
	52 weeks/year	8,760 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Rule Applicability Analysis

N/A - Facility is a Title V source

List of Applicable Regulations

See Appendix V for unit specific applicable requirements

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : S-1		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point) N/A - Type 1 emission point		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : N/A - Type 1 emission point		
5. Discharge Type Code :	V	
6. Stack Height :	65	feet
7. Exit Diameter :	10.0	feet
8. Exit Temperature :	718	°F
9. Actual Volumetric Flow Rate :	450000	acfm
10. Percent Water Vapor :		%
11. Maximum Dry Standard Flow Rate :		dscfm
12. Nonstack Emission Point Height :		feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 447.722 North (km) : 3127.685		
14. Emission Point Comment :		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning natural gas. This unit is allowed to operate on natural gas for an entire year (i.e., 8,760 hours).	
2. Source Classification Code (SCC) : 2-01-002-01	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 0.39	5. Maximum Annual Rate : 3,448.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 1,034	
10. Segment Comment : (407 mmBtu/h (HHV))/(1034 mmBtu/mscf (HHV)) = 0.394 mscf/h (0.394 mscf/h)x(8760 h/yr)= 3448 mscf/yr Based on baseload, ISO conditions as in ATC permit. Ref: 1034 mmBtu/mscf based on permit application.	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning No. 2 distillate fuel oil. During a natural gas curtailment, this unit is allowed to operate on No. 2 distillated fuel oil for an entire year (i.e., 8,760 hours).	
2. Source Classification Code (SCC) : 2-01-001-01	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 2.87	5. Maximum Annual Rate : 25,116.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 137	
10. Segment Comment : (397 MBtu/h)/(138 MBtu/thousand gal)= 2.87 thousand gal/h (2.87 thousand gal/h)x(8760 h/yr)= 25116 thousand gal/yr Ref: 137 mmBtu/thousand gal based on USEPA AP-42.	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Segment Description and Rate : Segment 3

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Simple Cycle Combustion Turbine burning No. 2 distillate fuel oil. When natural gas is available, this unit is allowed to operate on No. 2 distillated fuel oil for 1,000 hours per year.	
2. Source Classification Code (SCC) : 2-01-001-01	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 2.87	5. Maximum Annual Rate : 2,870.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 138	
10. Segment Comment : (397 MBtu/h (HHV))/(138 MBtu/thousand gal (HHV))= 2.87 thousand gal/h (2.87 thousand gal/h)x(1000 h/yr)= 2870 thousand gal/yr Based on baseload, ISO conditions as in ATC permit.	

Ref: 138 MBtu/thousand gal based on USEPA AP-42.

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
1 - PM			EL
2 - PM10			EL
3 - SO2	030		EL
4 - NOX	028		EL
5 - VOC			EL
6 - CO			EL
7 - H114			EL
8 - H015			EL
9 - H021			EL
10 - PB			EL
11 - H095			NS

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **PM**				
2. Total Percent Efficiency of Control :		%		
3. Potential Emissions :	11.98	lb/hour	52.49	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:			to	tons/year
6. Emissions Factor : Reference : Permit Limit				
7. Emissions Method Code : 0				
8. Calculations of Emissions : (0.0323 lbs/MBtu)x(371 MBtu/h) = 11.98 lb/h (11.98 lb/h)x(8760 h/yr)/(2000 lb/ton) = 52.49 tons/yr				
9. Pollutant Potential/Estimated Emissions Comment : Potential emissions equal allowable emissions for fuel oil firing.				

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.02	lb/MBtu		
4. Equivalent Allowable Emissions :	8.99	lb/hour	39.38	tons/year
5. Method of Compliance : Specific condition 9 of permit AC49-205703.				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for natural gas firing for 8,760 hours/year. Permit does not contain limits in lb/hour or ton/year. Stack tests only need to be conducted on the fuel types fired during the previous year.				

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.03	lb/MBtu		
4. Equivalent Allowable Emissions :	11.98	lb/hour	52.49	tons/year
5. Method of Compliance : Specific condition 9 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year in the event natural gas not available. Permit does not contain limits in lb/hour or ton/year. Stack tests only need to be conducted on fuel types fired during the previous year.				

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	0.03 lb/MBtu
4. Equivalent Allowable Emissions :	11.98 lb/hour 5.99 tons/year
5. Method of Compliance : Specific condition 9 of permit AC49-205703	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limit (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1,000 hours/year (n.g.avail). Permit does not contain limits in lb/hour or ton/year. Stack tests only need to be conducted on fuel types fired during the previous year.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **PM10**
2. Total Percent Efficiency of Control : %
3. Potential Emissions : 11.98 lb/hour 52.49 tons/year
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other Emissions: to tons/year
6. Emissions Factor : Reference : Permit Limit
7. Emissions Method Code : 0
8. Calculations of Emissions : (0.0323 lbs/MBtu)x(371 MBtu/h) = 11.98 lb/h (11.98 lb/h)x(8760 h/yr)/(2000 lb/ton) = 52.49 tons/yr
9. Pollutant Potential/Estimated Emissions Comment : Potential emissions equal allowable emissions for fuel oil firing.

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER	
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units : 0.02 lb/MBtu	
4. Equivalent Allowable Emissions : 8.99 lb/hour 39.37 tons/year	
5. Method of Compliance : Specific condition 9 of permit AC49-205703	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) are based on construction permit AC49-205703 for natural gas firing for 8,760 hours/year. Stack tests only need to be conducted on the fuel types fired during the previous year Permit does not contain limits in lb/hour or ton/year, .	

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.03	lb/MBtu		
4. Equivalent Allowable Emissions :	11.98	lb/hour	52.47	tons/year
5. Method of Compliance : Specific condition 9 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year (n.g. n/a). Stack tests only need to be conducted on the fuel types fired during previous year. Permit does not contain limits in lb/hour or ton/year.				

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	0.03 lb/MBtu
4. Equivalent Allowable Emissions :	11.98 lb/hour 5.99 tons/year
5. Method of Compliance : Specific condition 9 of permit AC49-205703	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limit (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1000 hours/year (n.g. avail). Stack tests only need to be conducted on the fuel types fired during previous year. Permit does not contain limits in lb/hour or ton/year.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 3

1. Pollutant Emitted : **SO2**				
2. Total Percent Efficiency of Control :	%			
3. Potential Emissions :	20.00	lb/hour	87.60	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:		to		tons/year
6. Emissions Factor : Reference : Permit condition				
7. Emissions Method Code : 0				
8. Calculations of Emissions : (20 lb/h)x(8,760 h/yr)/(2,000 ton/lb)= 87.6 tons/year				
9. Pollutant Potential/Estimated Emissions Comment : Maximum estimated emissions based on fuel oil firing.				

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	20.00	lb/h		
4. Equivalent Allowable Emissions :	20.00	lb/hour	87.60	tons/year
5. Method of Compliance : Specific condition 8 or 10 of permit & ASTM method D2880-94				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year (n.g. n/a). Stack tests only need to be conducted on the fuel types fired during previous year.				

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	20.00	lb/h		
4. Equivalent Allowable Emissions :	20.00	lb/hour	10.00	tons/year
5. Method of Compliance : Specific condition 8 or 10 of permit & ASTM method D2880-94				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limit (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1000 hours/year (n.g. avail). Stack tests only need to be conducted on the fuel types fired during previous year.				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **NOX**				
2. Total Percent Efficiency of Control :		%		
3. Potential Emissions :	63.00	lb/hour	275.90	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:			to	tons/year
6. Emissions Factor : Reference : Permit Limit				
7. Emissions Method Code : 0				
8. Calculations of Emissions : (63 lb/h)x(8760 h/yr)/(2000 lb/ton) = 275.9 tons/yr				
9. Pollutant Potential/Estimated Emissions Comment : Potential emission calculations based on conservative emission factor estimates (EPA FIRE) during fuel oil firing.				

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	25.00 ppm@15%O2
4. Equivalent Allowable Emissions :	36.00 lb/hour 157.68 tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for natural gas firing for 8,760 hours/year. Note the peremit listed 148.68 tpy for 8,260 hr/yr of natural gas operation and 19 tpy for the remaining 500 hy/yr of fuel oil firing (total 167.68 tpy). The above emissions are calculated assuming 8,760 hours of natural gas operation which is allowed by permit conditions 3 and 4.	

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :	01-Jan-1998			
3. Requested Allowable Emissions and Units :	15.00	ppm@15%O2		
4. Equivalent Allowable Emissions : 22.00	lb/hour	96.36	tons/year	

5. Method of Compliance :

Specific condition 8 of permit AC49-205703

6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :

Future allowable emission limit (in lbs/MBtu) from permit AC49-205703 for natural gas for 8,760 hours/year. Stack tests only need to be conducted on the fuel types fired during the previous year. Note the permit stated an annual emissions limit of 90.86 tpy for 8,260 hr/yr of natural gas operation and 19 tpy for the remaining 500 hr/yr of fuel oil firing (total 109.86 tpy). The above emissions are calculated assuming 8,760 hours of natural gas operation which is allowed by permit conditions 3 and 4. The NOx maximum limit will be lowered to 15 ppm@15%O2 by 1/1/98 using appropriate combustion technology improvements. Should this level of control not be achieved, the applicant will provide the Department with the expected compliance dates which will be updated annually.

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	42.00 ppm@15%O2
4. Equivalent Allowable Emissions :	63.00 lb/hour 275.90 tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year (n.g. n/a). Stack tests only need to be conducted on the fuel types fired during previous year.	

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 4

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	42.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	63.00	lb/hour	31.50	tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) are based on construction permit AC49-205703 for No.2distillate fuel oil firing for 1000 hours/year (n.g. avail). Stack tests only need to be conducted on the fuel types fired during previous year.				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **VOC**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 3.00 lb/hour 13.14 tons/year	
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor : Reference : Permit Limit	
7. Emissions Method Code : 0	
8. Calculations of Emissions : 3 lb/hr x 8,760 hr/yr x ton/2,000 lb	
9. Pollutant Potential/Estimated Emissions Comment :	

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	1.40	lb/h		
4. Equivalent Allowable Emissions :	1.40	lb/hour	6.13	tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for natural gas firing for 8,760 hours/year. NOTE: Permit lists tpy values for gas based on 8,260 hours of operation, assuming the remainder is on fuel oil (total 6.95 tpy; natural gas portion 5.8 tpy). Values above assume 8,760 hours of natural gas operation which is allowed by permit conditions 3 and 4.				

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	3.00 lb/h
4. Equivalent Allowable Emissions :	3.00 lb/hour 13.14 tons/year
5. Method of Compliance :	Specific condition 8 of permit AC49-205703
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :	Allowable emission limits (in lbs/MBtu) are based on construction permit AC49-205703 for No.2 distillate oil firing for 8,760 hours/year (n.g. n/a).

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	3.00	lb/h		
4. Equivalent Allowable Emissions :	3.00	lb/hour	1.50	tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) are based on construction permit AC49-205703 for No.2 distillate oil firing for 1000 hours/year (n.g. avail).				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **CO**				
2. Total Percent Efficiency of Control :	%			
3. Potential Emissions :	76.00	lb/hour	332.90	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:		to		tons/year
6. Emissions Factor : Reference : Permit Limit				
7. Emissions Method Code : 0				
8. Calculations of Emissions : 76 lb/hr x 8,760 hr/yr x ton/2,000 hrs				
9. Pollutant Potential/Estimated Emissions Comment :				

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	48.00	ppm		
4. Equivalent Allowable Emissions :	42.00	lb/hour	184.00	tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Per May 27, 1993 letter to FDEP and FDEP response of August 24, 1993. Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for natural gas firing for 8,760 hours/year. Note the permit stated an annual emissions limit of 165.2 tpy for 8,260 hr/yr of natural gas firing and 76 tpy of fuel oil firing (total 241.2 tpy). The above emissions are calculated assuming 8,760 hours of natural gas operation which is allowed by permit conditions 3 and 4.				

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	81.00	ppm		
4. Equivalent Allowable Emissions :	76.00	lb/hour	332.90	tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Per May 23, 1993 letter to FDEP and FDEP response of August 24, 1993. Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year (n.g. n/a).				

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	81.00	ppm		
4. Equivalent Allowable Emissions :	76.00	lb/hour	38.00	tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Per May 27, 1993 letter to FDEP and FDEP response of August 24, 1993. Allowable emission limit (in lbs/MBtu) from permit AC49-205703 for 31 No.2 fuel oil for 1000 hours/year (n.g. avail).				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 7

1. Pollutant Emitted : **H114**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 0.00 lb/hour 0.01 tons/year	
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor : Reference : Permit Limit	
7. Emissions Method Code : 0	
8. Calculations of Emissions : (3.1E-6 lbs/Mbtu)x(371 MBtu/hour) = < 0.01 lb/hr	
9. Pollutant Potential/Estimated Emissions Comment : Mercury (Hg)	

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 7

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.00	lb/MBtu		
4. Equivalent Allowable Emissions :	0.00	lb/hour	0.01	tons/year
5. Method of Compliance : Specific condition 12 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Emission factor 3.1x10(-6) lb/MBtu. Allowable emission limits (in lbs/mmBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year when natural gas is not available.				

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 7

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	0.00 lb/MBtu
4. Equivalent Allowable Emissions :	0.00 lb/hour 0.00 tons/year
5. Method of Compliance : Specific condition 12 of permit AC49-205703	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limit (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1,000 hours/year when natural gas is available.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 8

1. Pollutant Emitted : **H015**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 0.00 lb/hour 0.01 tons/year	
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor : Reference : Permit Limit	
7. Emissions Method Code : 0	
8. Calculations of Emissions : (4.2E-6 lbs/MBtu)x(371 MBtu/h) = <0.01 lb/h	
9. Pollutant Potential/Estimated Emissions Comment : Arsenic (As)	

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 8

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.00	lb/MBtu		
4. Equivalent Allowable Emissions :	0.00	lb/hour	0.01	tons/year
5. Method of Compliance : Initial stack testing or fuel sampling using DEP methods.				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Emission factor is 4.2x10(-6) lbs/MBtu. Allowable emission limits (in lbs/mmBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hrs/yr when natural gas is not available.				

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 8

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	0.00 lb/MBtu
4. Equivalent Allowable Emissions :	0.00 lb/hour 0.00 tons/year
5. Method of Compliance : Initial stack testing or fuel sampling using DEP methods.	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1000 hours/year when natural gas is available.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 9

1. Pollutant Emitted : **H021**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 0.00 lb/hour 0.00 tons/year	
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor : Reference : Permit Limit	
7. Emissions Method Code : 0	
8. Calculations of Emissions : (2.5E-6 lbs/MBtu)x(371 MBtu/h) = <0.01 lb/h	
9. Pollutant Potential/Estimated Emissions Comment : Beryllium (Be)	

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 9

Allowable Emissions 1

1. Basis for Allowable Emissions Code : OTHER	
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units : 0.00 lb/MBtu	
4. Equivalent Allowable Emissions : 0.00 lb/hour 0.00 tons/year	
5. Method of Compliance : Specific condition 11 of construction permit AC49-205703	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Emissiojn factor is 2.5x10(-6) lbs/MBtu. Allowable emission limits (in lbs/mmBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year when natural gas is not available.	

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 9

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.00	lb/MBtu		
4. Equivalent Allowable Emissions :	0.00	lb/hour	0.00	tons/year
5. Method of Compliance : Specific condition 11 of construction permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limit (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1000 hours/year when natural gas is available.				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 10

1. Pollutant Emitted : **PB**
2. Total Percent Efficiency of Control : %
3. Potential Emissions : 0.01 lb/hour 0.05 tons/year
4. Synthetically Limited? [ ] Yes [X] No
5. Range of Estimated Fugitive/Other Emissions: to tons/year
6. Emissions Factor : Reference : Permit Limit
7. Emissions Method Code : 0
8. Calculations of Emissions : (2.8E-5 lbs/MBtu)x(371 MBtu/hour) = <0.01 lb/h
9. Pollutant Potential/Estimated Emissions Comment :

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 10

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	0.00 lb/MBtu
4. Equivalent Allowable Emissions :	0.01 lb/hour 0.05 tons/year
5. Method of Compliance :	Heat input multiplied by emission factors/Initial stack test
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) :	Emission factor is 2.8x10(-5) lbs/MBtu. Allowable emission limit (in lbs/mmBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year when natural gas is not available.

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Information Section 10

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	0.00 lb/MBtu
4. Equivalent Allowable Emissions :	0.01 lb/hour 0.01 tons/year
5. Method of Compliance : Heat input multiplied by emission factors/Initial stack test	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limit (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1,000 hours/year when natural gas is available.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 11

1. Pollutant Emitted : **H095**				
2. Total Percent Efficiency of Control :		%		
3. Potential Emissions :	0.99	lb/hour	4.34	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:			to	tons/year
6. Emissions Factor : Reference : EPA FIRE 5.0				
7. Emissions Method Code : 3				
8. Calculations of Emissions : (0.0027 lbs/MBtu)x(367 MBtu/hour) = 0.99 lb/h (0.99 lb/h)x(8760 h/yr)/(2000 lbs/ton) = 4.34 tons/yr				
9. Pollutant Potential/Estimated Emissions Comment : Formaldehyde				

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :	VE		
2. Basis for Allowable Opacity :	OTHER		
3. Requested Allowable Opacity :			
Normal Conditions :		10	%
Exceptional Conditions :		20	%
Maximum Period of Excess Opacity Allowed :		6	min/hour
4. Method of Compliance : Annual testing using USEPA Method 9			
5. Visible Emissions Comment : VE10 visible emission limits based on construction permit AC49-205703.			

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 2

1. Visible Emissions Subtype : VE	
2. Basis for Allowable Opacity : RULE	
3. Requested Allowable Opacity : Normal Conditions : 20 % Exceptional Conditions : % Maximum Period of Excess Opacity Allowed : min/hour	
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity...	
5. Visible Emissions Comment : RULE for VE20: 62-296.310(2) General Visibility Emission Standard	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Continuous Monitoring System : Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant : NOX
3. CMS Requirement : OTHER	
4. Monitor Information : Manufacturer : TECO Model Number : 42D Serial Number : 42D-48216-280	
5. Installation Date : 01-Jun-1994	
6. Performance Specification Test Date : 28-Dec-1995	
7. Continuous Monitor Comment : OTHER: A continuous emission monitor required as a condition of construction permit AC49-205703 and 40 CFR Part 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Continuous Monitoring System : Continuous Monitor 2

1. Parameter Code : WTF	2. Pollutant :
3. CMS Requirement : RULE	
4. Monitor Information : Manufacturer : Johnson Yokogawa Model Number : GR2400 Serial Number : 45VG0706	
5. Installation Date : 11-Nov-1995	
6. Performance Specification Test Date : 11-Nov-1995	
7. Continuous Monitor Comment : RULE: New Source Performance Standards, 40 CFR 60, Subpart GG.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Continuous Monitoring System : Continuous Monitor 3

1. Parameter Code : FLOW	2. Pollutant :
3. CMS Requirement : OTHER	
4. Monitor Information : Manufacturer : Flow Technology Model Number : FT-20C3XBRLEA-5005 Serial Number : 2001833	
5. Installation Date : 01-Apr-1994	
6. Performance Specification Test Date : 21-Dec-1994	
7. Continuous Monitor Comment : Fuel oil flow monitor installed pursuant to 40 CFR Part 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1
Unit 1 - 40 MW Simple Cycle Combustion Turbine

Continuous Monitoring System : Continuous Monitor 4

1. Parameter Code : FLOW	2. Pollutant :
3. CMS Requirement : OTHER	
4. Monitor Information : Manufacturer : Yokogawa Model Number : YF105NNNA3A5353CFMFF Serial Number : 4032B007	
5. Installation Date : 01-Apr-1994	
6. Performance Specification Test Date : 21-Dec-1994	
7. Continuous Monitor Comment : Natural gas flow monitor installed pursuant to 40 CFR Part 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Continuous Monitoring System : Continuous Monitor 5

1. Parameter Code : O2	2. Pollutant :
3. CMS Requirement : OTHER	
4. Monitor Information : Manufacturer : Zerconium Oxide Model Number : 728 Serial Number : G-0407-948-E	
5. Installation Date : 01-Jun-1994	
6. Performance Specification Test Date : 28-Dec-1995	
7. Continuous Monitor Comment : OTHER: A continuous emission monitor required as a condition of construction permit AC49-205703 and 40 CFR Part 75..	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emission unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :				
	PM : C	SO2 : C	NO2 : C	
4. Baseline Emissions :				
	PM :	0.0000 lb/hour		0.0000 tons/year
	SO2 :	0.0000 lb/hour		0.0000 tons/year
	NO2 :			0.0000 tons/year
5. PSD Comment :				

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 1

Unit 1 - 40 MW Simple Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Appendix N
2. Fuel Analysis or Specification :	Appendix O
3. Detailed Description of Control Equipment :	Appendix P
4. Description of Stack Sampling Facilities :	Appendix Q
5. Compliance Test Report :	Appendix R
6. Procedures for Startup and Shutdown :	Appendix S
7. Operation and Maintenance Plan :	Appendix T
8. Supplemental Information for Construction Permit Application :	NA
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	Appendix U
11. Alterntive Modes of Operation (Emissions Trading) :	NA

12. Identification of Additional Applicable Requirements :	Appendix V
13. Compliance Assurance Monitoring Plan :	Appendix W

14. Acid Rain Application (Hard-copy Required) :

Appendix X	Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
NA	Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
NA	New Unit Exemption (Form No. 62-210.900(1)(a)2.)
NA	Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. Emissions Unit Information

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Type of Emissions Unit Addressed in This Section

1. 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.

2. Single Process, Group of Processes, or Fugitive Only? 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.

Emissions Unit Information Section 2

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Unit 2 - 120 MW Combined Cycle Combustion Turbine		
2. Emissions Unit Identification Number : 002 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : A	4. Acid Rain Unit? [X] Yes [ ] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : The 120 MW combined cycle combustion turbine is comprised of one 80 MW General Electric PG7111EA combustion turbine which exhausts through a heat recovery steam generator (HRSG) which is used to power a 40 MW steam turbine. Natural gas or low sulfur distillate fuel oil fired. Unit information throughout application is based on baseload, ISO conditions, commensurate with ATC permit AC49-205703		

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Emissions Unit Control Equipment 1

1. Description : Low NOx Burner: A technology that uses a two-stage combustor that premixes a portion of the air and fuel in the first stage and the remaining air and fuel are injected into the second stage.
2. Control Device or Method Code : 25

Emissions Unit Control Equipment 2

1. Description : Use of low sulfur fuel oil (0.05 percent) and the use of natural gas to control emissions of SO2.	
2. Control Device or Method Code :	30

Emissions Unit Control Equipment 3

1. Description : Water Injection: Used to limit NOx emissions by lowering the combustion temperature through the use of water injection. This will be used for fuel oil firing.	
2. Control Device or Method Code :	28

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Emissions Unit Details

1. Initial Startup Date :	29-Jan-1995	
2. Long-term Reserve Shutdown Date :		
3. Package Unit : Manufacturer : General Electric		Model Number : PG7111EA
4. Generator Nameplate Rating :	120 MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :		 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate :	869	mmBtu/hr	
2. Maximum Incinerator Rate :		lb/hr	tons/day
3. Maximum Process or Throughput Rate :			
4. Maximum Production Rate :			
5. Operating Capacity Comment : The heat input in field 1 is based on natural gas (baseload, ISO). The maximum heat input rate for distillate fuel oil No. 2 firing is 928 MBtu/hour (baseload, ISO). The corresponding HHV are 964 MBtu/hour (gas) and 992 MBtu/hour (oil).			

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule :	
24 hours/day	7 days/week
52 weeks/year	8,760 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Rule Applicability Analysis

N/A - Facility is a Title V source

List of Applicable Regulations

See Appendix EE for unit specific applicable regulations

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram :	S-2 HRSG/S-3 Bypass	
2. Emission Point Type Code :	3	
3. Descriptions of Emission Points Comprising this Emissions Unit : Two emission points are associated with the GE PG7111EA comb. turbine - the Bypass and HRSG.		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : N/A		
5. Discharge Type Code :	V	
6. Stack Height :	75	feet
7. Exit Diameter :	14.00	feet
8. Exit Temperature :	582	°F
9. Actual Volumetric Flow Rate :	660,000	acfm
10. Percent Water Vapor :		%
11. Maximum Dry Standard Flow Rate :		dscfm
12. Nonstack Emission Point Height :		feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 447.690 North (km) : 3,127.738		
14. Emission Point Comment : Exit temperature and flow rate conservatively reflect low load operation.		

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram :	S-2 HRSG/S-3 Bypass	
2. Emission Point Type Code :	3	
3. Descriptions of Emission Points Comprising this Emissions Unit : Alternatively, when the GE PG7111EA combustion turbine is operating in the simple cycle mode, the ex		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : N/A		
5. Discharge Type Code :	V	
6. Stack Height :	75	feet
7. Exit Diameter :	14.00	feet
8. Exit Temperature :	582	°F
9. Actual Volumetric Flow Rate :	660,000	acfm
10. Percent Water Vapor :		%
11. Maximum Dry Standard Flow Rate :		dscfm
12. Nonstack Emission Point Height :		feet
13. Emission Point UTM Coordinates : Zone : 17 East (km) : 447.690 North (km) : 3,127.738		
14. Emission Point Comment : Exit temperature and flow rate conservatively reflect low load operation.		

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Combustion turbine operating in either combined cycle or simple cycle mode on natural gas. This unit is allowed to operate on natural gas for an entire year (i.e., 8,760 hours).	
2. Source Classification Code (SCC) : 2-01-002-01	
3. SCC Units : Million Cubic Feet Burned (all gaseous fuels)	
4. Maximum Hourly Rate : 0.93	5. Maximum Annual Rate : 8,167.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 1,034	
10. Segment Comment : (964 mmBtu/h (HHV))/(1034 mmBtu/mscf (HHV))= 0.93 mscf/h (0.93 mscf/h)x(8760 h/yr)= 8167 mscf/yr Ref: 1034 mmBtu/mscf based on permit application, baseload, ISO.	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Combustion turbine operating in either combined cycle or simple cycle mode on No. 2 distillate fuel oil. When natural gas is not available, this unit is allowed to operate on No. 2 distillate fuel oil for an entire year (i.e., 8,760 hours).	
2. Source Classification Code (SCC) : 2-01-001-01	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 7.16	5. Maximum Annual Rate : 62,759.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 138	
10. Segment Comment : (992 mmBtu/h (HHV))/(138 mmBtu/thousand gal (HHV))= 7.16 thousand gal/h (7.16 thousand gal/h)x(8760 h/yr) = 62759 thousand gal/yr Ref: 138 mmBtu/thousand gal based on fuel analysis.	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Segment Description and Rate : Segment 3

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Combustion turbine operating in either combined cycle or simple cycle mode on No. 2 distillate fuel oil. When natural gas is available, this unit is allowed to operate on No. 2 distillate fuel oil for 1,000 hours per year.	
2. Source Classification Code (SCC) : 2-01-001-01	
3. SCC Units : Thousand Gallons Burned (all liquid fuels)	
4. Maximum Hourly Rate : 7.16	5. Maximum Annual Rate : 7,160.00
6. Estimated Annual Activity Factor :	
7. Maximum Percent Sulfur : 0.05	8. Maximum Percent Ash :
9. Million Btu per SCC Unit : 138	
10. Segment Comment : (992 mmBtu/h (HHV))/(138 mmBtu/thousand gal (HHV))= 7.16 thousand gal/h (7.16 thousand gal/h)x(1000 h/yr) = 7160 thousand gal/yr Ref: 138 mmBtu/thousand gal based on fuel analysis.	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
11 - H095			NS
1 - PM			EL
2 - PM10			EL
3 - SO2	030		EL
4 - NOX	025	028	EL
5 - VOC			EL
6 - CO			EL
7 - H114			EL
8 - H015			EL
9 - H021			EL
10 - PB			EL

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **PM**				
2. Total Percent Efficiency of Control :		%		
3. Potential Emissions :	15.03	lb/hour	65.85	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:			to	tons/year
6. Emissions Factor : Reference : Permit Limit				
7. Emissions Method Code : 0				
8. Calculations of Emissions : (0.0162 lb/MBtu)x(928 MBtu/h) = 15.03 lb/h (15.03 lb/h)x(8760 h/yr)/(2000 lb/ton) = 65.85 tons/year				
9. Pollutant Potential/Estimated Emissions Comment :				

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.01	lb/MBtu		
4. Equivalent Allowable Emissions :	8.69	lb/hour	38.06	tons/year
5. Method of Compliance : Specific condition 9 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for natural gas firing for 8,760 hours/year. Stack tests only need to be conducted on the fuel types fired during the previous year. Permit does not contain limits in lb/hour or tons/year.				

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	0.02 lb/MBtu
4. Equivalent Allowable Emissions :	15.03 lb/hour 65.85 tons/year
5. Method of Compliance : Specific condition 9 of permit AC49-205703	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Emission factor is 0.0162 lbs/MBtu. Allowable emission limits (in lbs/mmBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year when natural gas is not available. Stack tests only need to be conducted on the fuel types fired during previous year.	

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 1

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	0.02 lb/MBtu
4. Equivalent Allowable Emissions :	15.03 lb/hour 7.52 tons/year
5. Method of Compliance : Specific condition 9 of permit AC49-205703	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limit (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1000 hours/year when natural gas is available. Stack tests only need to be conducted on the fuel types fired during previous year.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 2

1. Pollutant Emitted : **PM10**				
2. Total Percent Efficiency of Control :		%		
3. Potential Emissions :	15.03	lb/hour	65.85	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:			to	tons/year
6. Emissions Factor : Reference : Permit Limit				
7. Emissions Method Code : 0				
8. Calculations of Emissions : (0.0162 lb/MBtu)x(928 MBtu/h) = 15.03 lb/h (15.03 lb/h)x(8760 h/yr)/(2000 lb/ton) = 65.85 tons/yr				
9. Pollutant Potential/Estimated Emissions Comment :				

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.01	lb/MBtu		
4. Equivalent Allowable Emissions :	8.69	lb/hour	38.06	tons/year
5. Method of Compliance : Specific condition 9 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for natural gas firing for 8,760 hours/year. Stack tests only need to be conducted on the fuel types fired during the previous year.				

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.02	lb/MBtu		
4. Equivalent Allowable Emissions :	15.03	lb/hour	65.85	tons/year
5. Method of Compliance : Specific condition 9 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year when natural gas is not available. Stack tests only need to be conducted on the fuel types fired during previous year.				

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 2

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.02	lb/MBtu		
4. Equivalent Allowable Emissions :	15.03	lb/hour	7.52	tons/year
5. Method of Compliance : Specific condition 9 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limit (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1000 hours/year when natural gas is available. Stack tests only need to be conducted on the fuel types fired during previous year.				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 3

1. Pollutant Emitted : **SO2**				
2. Total Percent Efficiency of Control :		%		
3. Potential Emissions :	52.00	lb/hour	228.00	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:			to	tons/year
6. Emissions Factor : Reference : Permit Condition				
7. Emissions Method Code : 0				
8. Calculations of Emissions : (52 lb/h)x(8760 h/yr)/(2000 lb/ton) = 228 tons/year				
9. Pollutant Potential/Estimated Emissions Comment : Maximum estimated emissions based on fuel oil firing.				

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	52.00	lb/h		
4. Equivalent Allowable Emissions :	52.00	lb/hour	228.00	tons/year
5. Method of Compliance : Specific condition 8 or 10 of permit & ASTM method D2880-94				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year when natural gas is not available. Stack tests only need to be conducted on the fuel types fired during previous year.				

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 3

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	52.00	lb/h		
4. Equivalent Allowable Emissions :	52.00	lb/hour	26.00	tons/year
5. Method of Compliance : Specific condition 8 or 10 of permit & ASTM method D2880-94				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limit (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1000 hours/year when natural gas is available. Stack tests only need to be conducted on the fuel types fired during previous year.				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 4

1. Pollutant Emitted : **NOX**	
2. Total Percent Efficiency of Control :	%
3. Potential Emissions : 170.00 lb/hour	745.00 tons/year
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions:	to tons/year
6. Emissions Factor : Reference : Permit Limit	
7. Emissions Method Code : 3	
8. Calculations of Emissions : (170 lb/h)x(8760 h/yr)/(2000 lb/ton) = 745 tons/yr	
9. Pollutant Potential/Estimated Emissions Comment :	

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	25.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	98.00	lb/hour	429.24	tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for natural gas firing for 8,760 hours/year. Stack tests only need to be conducted on the fuel types fired during the previous year. Note that permit AC49-205703 listed 405 tpy for 8260 hr/yr of natural gas operation and 45 tpy for the remaining 500 hr/yr of fuel oil firing (total 448 tpy). The above emissions are calculated assuming 8760 hr/yr of natural gas operation as allowed by permit conditions 3 and 4.				

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :	01-Jan-1998			
3. Requested Allowable Emissions and Units :	15.00	ppm@15%O2		
4. Equivalent Allowable Emissions : 53.00	lb/hour	232.14	tons/year	
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Future allowable emission limit (in lbs/MBtu) from permit AC49-205703 for natural gas for 8,760 hours/year. Stack tests only need to be conducted on the fuel types fired during the previous year. Note that permit AC49-205703 listed 219 tpy for 8260 hr/yr of natural gas operation and 43 tpy for the remaining 500 hr/yr of fuel oil firing (total 262 tpy). The above emissions are calculated assuming 8760 hr/yr of natural gas operation as allowed by permit conditions 3 and 4.				

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	42.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	170.00	lb/hour	745.00	tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year natural gas not available. Stack tests only need to be conducted on the fuel types fired during previous year.				

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 4

Allowable Emissions 4

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	42.00	ppm@15%O2		
4. Equivalent Allowable Emissions :	170.00	lb/hour	85.00	tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1000 hours/year (n.g.avail). Stack tests only need to be conducted on the fuel types fired during previous year.				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 5

1. Pollutant Emitted : **VOC**	
2. Total Percent Efficiency of Control : %	
3. Potential Emissions : 5.00 lb/hour 21.90 tons/year	
4. Synthetically Limited? [ ] Yes [X] No	
5. Range of Estimated Fugitive/Other Emissions: to tons/year	
6. Emissions Factor : Reference : Permit Limit	
7. Emissions Method Code : 0	
8. Calculations of Emissions : (5 lb/h)x(8760 h/yr)/(2000 lb/ton) = 21.9 tons/yr (@ ISO)	
9. Pollutant Potential/Estimated Emissions Comment : Potential emission equal allowable emissions for fuel oil firing.	

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	2.00	lb/h		
4. Equivalent Allowable Emissions :	2.00	lb/hour	8.76	tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for natural gas firing for 8,760 hours/year. Stack tests only need to be conducted on the fuel types fired during the previous year. Note that permit AC49-205703 listed 8.3 tpy for 8260 hr/yr of natural gas operation and 1.3 tpy for the remaining 500 hr/yr of fuel oil firing (total 9.6 tpy). The above emissions are calculated assuming 8760 hr/yr of natural gas operation as allowed by permit conditions 3 and 4.				

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	5.00	lb/h		
4. Equivalent Allowable Emissions :	5.00	lb/hour	21.90	tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year when natural gas is not available. Stack tests only need to be conducted on the fuel types fired during previous year.				

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 5

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	5.00	lb/h		
4. Equivalent Allowable Emissions :	5.00	lb/hour	2.50	tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1000 hours/year when natural gas is available. Stack tests only need to be conducted on the fuel types fired during previous year.				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 6

1. Pollutant Emitted : **CO**				
2. Total Percent Efficiency of Control :	%			
3. Potential Emissions :	65.00	lb/hour	285.00	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:			to	tons/year
6. Emissions Factor : Reference : Permit Limit				
7. Emissions Method Code : 0				
8. Calculations of Emissions : (65 lb/h)x(8760 h/yr)/(2000 lb/ton) = 285 tons/yr				
9. Pollutant Potential/Estimated Emissions Comment : Potential emissions equal allowable emissions for fuel oil firing.				

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	25.00	ppm		
4. Equivalent Allowable Emissions :	54.00	lb/hour	236.52	tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for natural gas firing for 8,760 hours/year. Emission levels based on May 27, 1993 letter to the DEP and August 24, 1993 response. Stack tests only need to be conducted on the fuel types fired during the previous year. Note that permit AC49-205703 listed 223 tpy for 8260 hr/yr of natural gas operation and 16 tpy for the remaining 500 hr/yr of fuel oil firing (total 239 tpy). The above emissions are calculated assuming 8760 hr/yr of natural gas operation as allowed by permit conditions 3 and 4.				

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	20.00 ppm
4. Equivalent Allowable Emissions :	65.00 lb/hour 285.00 tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limits (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year when natural gas is not available. Stack tests only need to be conducted on the fuel types fired during previous year.	

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 6

Allowable Emissions 3

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	20.00 ppm
4. Equivalent Allowable Emissions :	65.00 lb/hour 32.50 tons/year
5. Method of Compliance : Specific condition 8 of permit AC49-205703	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limit (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1000 hours/year when natural gas is available. Stack tests only need to be conducted on the fuel types fired during previous year.	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 7

1. Pollutant Emitted : **H114**				
2. Total Percent Efficiency of Control :		%		
3. Potential Emissions :	0.00	lb/hour	0.00	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:			to	tons/year
6. Emissions Factor : Reference : Permit Limit				
7. Emissions Method Code : 0				
8. Calculations of Emissions : (3.0E-6 lb/MBtu)x(928 mmBtu/h(LHV @ISO))= <0.01 lb/h				
9. Pollutant Potential/Estimated Emissions Comment : Mercury (Hg)				

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 7

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.00	lb/MBtu		
4. Equivalent Allowable Emissions :	0.00	lb/hour	0.01	tons/year
5. Method of Compliance : Speicific condition 12 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Emission factor is 3.0x10(-6) lbs/MBtu. Allowable emission limits (in lbs/mmBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year (n.g. n/a).				

DEP Form No. 62-210.900(1) - Form
Effective : 3-21-96

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 7

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.00	lb/mmBtu		
4. Equivalent Allowable Emissions :	0.00	lb/hour	0.00	tons/year
5. Method of Compliance : Speicific condition 12 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limit (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1000 hours/year (n.g. avail).				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 8

1. Pollutant Emitted : **H015**				
2. Total Percent Efficiency of Control :		%		
3. Potential Emissions :	0.00	lb/hour	0.02	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:			to	tons/year
6. Emissions Factor : Reference : Permit Limit				
7. Emissions Method Code : 0				
8. Calculations of Emissions : (4.2E-6 lb/MBtu)x(928 mmBtu/h(LHV@ISO))= <0.01 lb/hr				
9. Pollutant Potential/Estimated Emissions Comment : Arsenic (As)				

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 8

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.00	lb/MBtu		
4. Equivalent Allowable Emissions :	0.00	lb/hour	0.02	tons/year
5. Method of Compliance : Initial stack testing using DEP approved methods.				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Emission factor is 4.2x10(-6) lbs/MBtu. Allowable emission limits (in lbs/mmBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year (n.g. n/a).				

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 8

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	0.00 lb/MBtu
4. Equivalent Allowable Emissions :	0.00 lb/hour 0.00 tons/year
5. Method of Compliance : Initial stack testing using DEP approved methods.	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limit (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1000 hours/year (n.g. avail).	

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 9

1. Pollutant Emitted : **H021**				
2. Total Percent Efficiency of Control :		%		
3. Potential Emissions :	0.00	lb/hour	0.00	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:			to	tons/year
6. Emissions Factor : Reference : Permit Limit				
7. Emissions Method Code : 0				
8. Calculations of Emissions : (2.5E-6 lb/MBtu)x(928 mmBtu/h (LHV@ISO)) = 0.0023 lb/hour				
9. Pollutant Potential/Estimated Emissions Comment : Beryllium (Be)				

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 9

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.00	lb/MBtu		
4. Equivalent Allowable Emissions :	0.00	lb/hour	0.01	tons/year
5. Method of Compliance : Specific condition 11 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Emission factor is 2.5x10(-6) lbs/MBtu. Allowable emission limits (in lbs/mmBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year when natural gas is not available. Stack test only needs to be conducted on the fuel types fired during previous year.				

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 9

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.00	lb/MBtu		
4. Equivalent Allowable Emissions :	0.00	lb/hour	0.00	tons/year
5. Method of Compliance : Specific condition 11 of permit AC49-205703				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limit (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1000 hours/year when natural gas is available. Stack test only needs to be conducted on the fuel types fired during previous year.				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 10

1. Pollutant Emitted : **PB**				
2. Total Percent Efficiency of Control :		%		
3. Potential Emissions :	0.03	lb/hour	0.11	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:			to	tons/year
6. Emissions Factor : Reference : Permit Limit				
7. Emissions Method Code : 0				
8. Calculations of Emissions : (2.5E-5 lb/MBtu)x(928 MBtu/h) = 0.03 lb/h (0.03 lb/h)x(8760 h/yr)/(2000 lb/ton) = 0.11 tons/yr				
9. Pollutant Potential/Estimated Emissions Comment : Lead (Pb)				

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 10

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.00	lb/MBtu		
4. Equivalent Allowable Emissions :	0.03	lb/hour	0.11	tons/year
5. Method of Compliance : Heat input multiplied by emission factors/Initial stack test				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Emission factor is 2.8x10(-5) lbs/MBtu. Allowable emission limits (in lbs/mmBtu) from permit AC49-205703 for No.2 fuel oil for 8,760 hours/year when natural gas is not available.				

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Information Section 10

Allowable Emissions 2

1. Basis for Allowable Emissions Code :	OTHER			
2. Future Effective Date of Allowable Emissions :				
3. Requested Allowable Emissions and Units :	0.00	lb/MBtu		
4. Equivalent Allowable Emissions :	0.03	lb/hour	0.01	tons/year
5. Method of Compliance : Heat input multiplied by emission factors/Initial stack test				
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : Allowable emission limit (in lbs/MBtu) from permit AC49-205703 for No.2 fuel oil for 1000 hours/year when natural gas is available.				

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Pollutant Potential/Estimated Emissions : Pollutant 11

1. Pollutant Emitted : **H095**				
2. Total Percent Efficiency of Control :		%		
3. Potential Emissions :	2.35	lb/hour	10.28	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:			to	tons/year
6. Emissions Factor : Reference : EPA FIRE 5.0				
7. Emissions Method Code : 3				

8. Calculations of Emissions :

(869 MBtu/h) X (0.0027 lb/mmBtu) = 2.35 lb/h
(0.99 lb/h) X (8760 h/yr)/(2000 lbs/ton) = 10.27 tons/yr
Ref: EPA FIRE Version 5.0 (August 1995)
Ref: 869 mmBtu/h is the maximum heat input for natural gas firing based on the lower heating value (LHV).

9. Pollutant Potential/Estimated Emissions Comment :

Formaldehyde

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 1

1. Visible Emissions Subtype :	VE		
2. Basis for Allowable Opacity :	OTHER		
3. Requested Allowable Opacity :			
Normal Conditions :	10	%	
Exceptional Conditions :	20	%	
Maximum Period of Excess Opacity Allowed :	6	min/hour	
4. Method of Compliance : USEPA Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources.			
5. Visible Emissions Comment : For VE10, the visible emission limits based on construction permit AC49-205703.			

I. VISIBLE EMISSIONS INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Visible Emissions Limitation : Visible Emissions Limitation 2

1. Visible Emissions Subtype : VE	
2. Basis for Allowable Opacity :	
3. Requested Allowable Opacity : Normal Conditions : 20 % Exceptional Conditions : % Maximum Period of Excess Opacity Allowed : min/hour	
4. Method of Compliance : USEPA Method 9 - Visual Determination of Opacity...	
5. Visible Emissions Comment : RULE for VE20: 62-296.310(2) General Visibility Emission Standard	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Continuous Monitoring System : Continuous Monitor 1

1. Parameter Code : EM	2. Pollutant : NOX
3. CMS Requirement : OTHER	
4. Monitor Information : Manufacturer : TECO Model Number : 42D Serial Number : 42D-47851-277	
5. Installation Date : 01-Jun-1994	
6. Performance Specification Test Date : 27-Dec-1995	
7. Continuous Monitor Comment : OTHER: A continuous emission monitor (CEM) is required as a condition of the construction permit AC49-205703 and 40 CFR Part 75. This CEM is installed on the HRSG stack.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Continuous Monitoring System : Continuous Monitor 2

1. Parameter Code : EM	2. Pollutant : NOX
3. CMS Requirement : OTHER	
4. Monitor Information : Manufacturer : TECO Model Number : 42D Serial Number : 42D-47918-279	
5. Installation Date : 01-Apr-1994	
6. Performance Specification Test Date : 27-Dec-1995	
7. Continuous Monitor Comment : OTHER: A continuous emission monitor (CEM) is required as a condition of the construction permit AC49-205703 and 40 CFR Part 75. This CEM is installed on the by-pass stack.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Continuous Monitoring System : Continuous Monitor 3

1. Parameter Code : WTF	2. Pollutant :
3. CMS Requirement : RULE	
4. Monitor Information : Manufacturer : General Electric Model Number : Part of GE 7EA Serial Number : 9312-34846-1-1	
5. Installation Date : 01-Apr-1994	
6. Performance Specification Test Date : 21-Apr-1995	
7. Continuous Monitor Comment : RULE: New Source Performance Standards, 40 CFR 60, Subpart GG. Water injection flow ratio and monitoring are integrated into the GE 7EA combustion turbine.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Continuous Monitoring System : Continuous Monitor 4

1. Parameter Code : FLOW	2. Pollutant :
3. CMS Requirement : OTHER	
4. Monitor Information : Manufacturer : General Electric Model Number : Part of GE 7EA Serial Number : 9312-34846-1-1	
5. Installation Date : 01-Apr-1994	
6. Performance Specification Test Date : 21-Apr-1995	
7. Continuous Monitor Comment : Fuel oil flow monitoring is integrated into the GE 7EA combustion turbine. Operated pursuant to 40 CFR Part 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Continuous Monitoring System : Continuous Monitor 5

1. Parameter Code : FLOW	2. Pollutant :
3. CMS Requirement : OTHER	
4. Monitor Information : Manufacturer : Rosemount Model Number : 1151 Serial Number : 209977	
5. Installation Date : 01-Apr-1994	
6. Performance Specification Test Date : 21-Apr-1995	
7. Continuous Monitor Comment : Natural gas flow monitor installed pursuant to 40 CFR Part 75.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Continuous Monitoring System : Continuous Monitor 6

1. Parameter Code : O2	2. Pollutant :
3. CMS Requirement : OTHER	
4. Monitor Information : Manufacturer : Zirconium Oxide Model Number : 728 Serial Number : 2558009	
5. Installation Date : 01-Jun-1994	
6. Performance Specification Test Date : 27-Dec-1995	
7. Continuous Monitor Comment : OTHER: A continuous emission monitor (CEM) is required as a condition of the construction permit AC49-205703 and 40 CFR Part 75. This CEM is installed on the HRSG stack.	

J. CONTINUOUS MONITOR INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 2
Unit 2 - 120 MW Combined Cycle Combustion Turbine

Continuous Monitoring System : Continuous Monitor 7

1. Parameter Code : O2	2. Pollutant :
3. CMS Requirement : OTHER	
4. Monitor Information : Manufacturer : Zirconium Oxide Model Number : 728 Serial Number : G-0407-948-E	
5. Installation Date : 01-Apr-1994	
6. Performance Specification Test Date : 27-Dec-1995	
7. Continuous Monitor Comment : OTHER: A continuous emission monitor (CEM) is required as a condition of the construction permit AC49-205703 and 40 CFR Part 75. This CEM is installed on the by-pass stack.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[X] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[X] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emission unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :			
PM : C	SO2 : C	NO2 : C	
4. Baseline Emissions :			
PM :	0.0000 lb/hour	0.0000 tons/year	
SO2 :	0.0000 lb/hour	0.0000 tons/year	
NO2 :		0.0000 tons/year	
5. PSD Comment :			

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 2

Unit 2 - 120 MW Combined Cycle Combustion Turbine

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Appendix Y
2. Fuel Analysis or Specification :	Appendix O
3. Detailed Description of Control Equipment :	Appendix Z
4. Description of Stack Sampling Facilities :	Appendix AA
5. Compliance Test Report :	Appendix R
6. Procedures for Startup and Shutdown :	Appendix BB
7. Operation and Maintenance Plan :	Appendix CC
8. Supplemental Information for Construction Permit Application :	NA
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	Appendix DD
11. Alterntive Modes of Operation (Emissions Trading) :	NA

12. Identification of Additional Applicable Requirements :	Appendix EE
13. Compliance Assurance Monitoring Plan :	Appendix FF

14. Acid Rain Application (Hard-copy Required) :

Appendix X	Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
	Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
	New Unit Exemption (Form No. 62-210.900(1)(a)2.)
	Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. Emissions Unit Information

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 3

Distillate Fuel Oil Storage Tank (300,000 gal) No. 1

Type of Emissions Unit Addressed in This Section

1. 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.

2. Single Process, Group of Processes, or Fugitive Only? 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.

Emissions Unit Information Section 3

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

<table>
<tr><td colspan="3">1. Description of Emissions Unit Addressed in This Section :

Distillate Fuel Oil Storage Tank (300,000 gal) No. 1</td></tr>
<tr><td colspan="3">2. Emissions Unit Identification Number : 003
[ ] No Corresponding ID [ ] Unknown</td></tr>
<tr><td>3. Emissions Unit Status Code : A</td><td>4. Acid Rain Unit?
[ ] Yes [X] No</td><td>5. Emissions Unit Major Group SIC Code : 49</td></tr>
<tr><td colspan="3">6. Emissions Unit Comment :

This distillate fuel oil storage tank (300,000 gal) is reported as an emission unit because it is subject to regulations based on the emissions guidelines of the New Source Performance Standards 40 CFR 60, Subpart Kb.

The tank is a verticle fixed roof design.</td></tr>
</table>

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Distillate Fuel Oil Storage Tank (300,000 gal) No. 1

Emissions Unit Details

1. Initial Startup Date :	01-Aug-1994
2. Long-term Reserve Shutdown Date :	
3. Package Unit : Manufacturer : Advance Tank Company	Model Number : N/A
4. Generator Nameplate Rating :	MW
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :	 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate :	mmBtu/hr	
2. Maximum Incinerator Rate :	lb/hr	tons/day
3. Maximum Process or Throughput Rate :	24900	thousand gal/yr
4. Maximum Production Rate :		
5. Operating Capacity Comment : The maximum throughput rate corresponds to use of No. 2 fuel oil for 8760 hours/year (natural gas not available). When n.g. is available, No.2 fuel oil firing limited to 1000 hours/year.		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule :	
24 hours/day	7 days/week
52 weeks/year	8,760 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 3
Distillate Fuel Oil Storage Tank (300,000 gal) No. 1

Rule Applicability Analysis

N/A

List of Applicable Regulations

See Appendix II for list of applicable regulations.

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 3

Distillate Fuel Oil Storage Tank (300,000 gal) No. 1

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : S-4		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point) The emission point for a vertical fixed roof storage tank is the breather valve on the dome roof.		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : The are two types of emissions associated with the breather valve of a vertical fixed roof storage tank as described below. 1) Storage Loss: Emissions resulting from the expulsion of vapor from a tank through vapor expansion and contraction which are the result of changes in ambient temperature and barometric pressure. (Also known as standing loss) 2) Working Loss: Emissions resulting from the filling and emptying of the storage tank which are associated with the change in liquid level within the tank.		
5. Discharge Type Code :	P	
6. Stack Height :		feet
7. Exit Diameter :		feet
8. Exit Temperature :	77	°F
9. Actual Volumetric Flow Rate :		acfm
10. Percent Water Vapor :		%
11. Maximum Dry Standard Flow Rate :		dscfm
12. Nonstack Emission Point Height :	44	feet
13. Emission Point UTM Coordinates :		

Zone :	17	East (km) :	447.780	North (km) :	3127.670

14. Emission Point Comment :

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 3

Distillate Fuel Oil Storage Tank (300,000 gal) No. 1

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Storage Loss: Emissions resulting from the expulsion of vapor from a tank through vapor expansion and contraction which are the result of changes in ambient temperature and barometric pressure. (Also known as standing loss or breathing loss)	
2. Source Classification Code (SCC) : 4-03-010-19	
3. SCC Units : Thousand Gallons Stored	
4. Maximum Hourly Rate :	5. Maximum Annual Rate :
6. Estimated Annual Activity Factor : 300.00	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment :	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 3

Distillate Fuel Oil Storage Tank (300,000 gal) No. 1

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Working Loss: Emissions resulting from the filling and emptying of the storage tank which are associated with the change in liquid level within the tank. This segment assumes a natural gas curtailment. Accordingly, No.2 distillate fuel oil would be used the entire year (i.e. 8760 hours per year).	
2. Source Classification Code (SCC) : 4-03-010-21	
3. SCC Units : Thousand Gallons Transferred or Handled	
4. Maximum Hourly Rate :	5. Maximum Annual Rate :
6. Estimated Annual Activity Factor : 24,900.00	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment :	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 3

Distillate Fuel Oil Storage Tank (300,000 gal) No. 1

Segment Description and Rate : Segment 3

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Working Loss: Emissions resulting from the filling and emptying of the storage tank which are associated with the change in liquid level within the tank. This segment assumes that natural gas is available. Accordingly, No.2 distillate fuel oil use would be limited to 1000 hours per year.	
2. Source Classification Code (SCC) : 4-03-010-21	
3. SCC Units : Thousand Gallons Transferred or Handled	
4. Maximum Hourly Rate :	5. Maximum Annual Rate :
6. Estimated Annual Activity Factor : 2,840.00	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment :	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 3
Distillate Fuel Oil Storage Tank (300,000 gal) No. 1

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

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 3
Distillate Fuel Oil Storage Tank (300,000 gal) No. 1

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **VOC**				
2. Total Percent Efficiency of Control :	%			
3. Potential Emissions :	0.05	lb/hour	0.22	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:		to		tons/year
6. Emissions Factor : Reference : TANKS 2.0				
7. Emissions Method Code : 3				
8. Calculations of Emissions : Emission calculations are based on USEPA's TANKS Version 2.0 program (January, 1995) which included both breathing and working loss emissions. The lb/hour emission factor is estimated based on the annual emission factor obtained from TANKS (assumes 8,760 hours/year). See Appendix MM for TANKS output report.				
9. Pollutant Potential/Estimated Emissions Comment : Maximum estimated emissions based on No.2 distillate fuel oil firing for an entire year in the event natural gas is not available.				

Emissions Unit Information Section 3
Distillate Fuel Oil Storage Tank (300,000 gal) No. 1

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code :	RULE
2. Future Effective Date of Allowable Emissions :	
3. Requested Allowable Emissions and Units :	
4. Equivalent Allowable Emissions : lb/hour	tons/year
5. Method of Compliance : As specified in 40 CFR 60.116 (a) and (b), Subpart Kb.	
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: From 40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construcion, Reconstruction, or Modification Commenced after July 23, 1984.	

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 3

Distillate Fuel Oil Storage Tank (300,000 gal) No. 1

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[ ] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[ ] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emission unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :		
PM :	SO2 :	NO2 :
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		
Tank does not emit PSD increment consuming pollutants.		

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 3

Distillate Fuel Oil Storage Tank (300,000 gal) No. 1

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Appendix GG
2. Fuel Analysis or Specification :	NA
3. Detailed Description of Control Equipment :	NA
4. Description of Stack Sampling Facilities :	NA
5. Compliance Test Report :	NA
6. Procedures for Startup and Shutdown :	NA
7. Operation and Maintenance Plan :	NA
8. Supplemental Information for Construction Permit Application :	NA
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	Appendix HH
11. Alterntive Modes of Operation (Emissions Trading) :	NA

12. Identification of Additional Applicable Requirements :	Appendix II
13. Compliance Assurance Monitoring Plan :	NA
14. Acid Rain Application (Hard-copy Required) :	
NA	Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
NA	Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
NA	New Unit Exemption (Form No. 62-210.900(1)(a)2.)
NA	Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

III. Emissions Unit Information

III. EMISSIONS UNIT INFORMATION

A. TYPE OF EMISSIONS UNIT
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank (700,000 gal) No. 2

<u>Type of Emissions Unit Addressed in This Section</u>

1. 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.

2. Single Process, Group of Processes, or Fugitive Only? 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.

Emissions Unit Information Section 4

B. GENERAL EMISSIONS UNIT INFORMATION
(Regulated and Unregulated Emissions Units)

Emissions Unit Description and Status

1. Description of Emissions Unit Addressed in This Section : Distillate Fuel Oil Storage Tank (700,000 gal) No. 2		
2. Emissions Unit Identification Number : 004 [ ] No Corresponding ID [ ] Unknown		
3. Emissions Unit Status Code : A	4. Acid Rain Unit? [ ] Yes [X] No	5. Emissions Unit Major Group SIC Code : 49
6. Emissions Unit Comment : This distillate fuel oil storage tank (700,000 gal) is reported as an emission unit because it is subject to regulations based on the emissions guidelines of the New Source Performance Standards 40 CFR 60, Subpart Kb. The tank is a verticle fixed roof design.		

C. EMISSIONS UNIT DETAIL INFORMATION
(Regulated Emissions Units Only)

Emissions Unit Information Section 4
Distillate Fuel Oil Storage Tank (700,000 gal) No. 2

Emissions Unit Details

1. Initial Startup Date :	29-Jan-1995	
2. Long-term Reserve Shutdown Date :		
3. Package Unit : Manufacturer : Advance Tank Company		Model Number : N/A
4. Generator Nameplate Rating :	MW	
5. Incinerator Information : Dwell Temperature : Dwell Time : Incinerator Afterburner Temperature :		 Degrees Fahrenheit Seconds Degrees Fahrenheit

Emissions Unit Operating Capacity

1. Maximum Heat Input Rate :	mmBtu/hr	
2. Maximum Incinerator Rate :	lb/hr	tons/day
3. Maximum Process or Throughput Rate :	58100	thousand gal/yr
4. Maximum Production Rate :		
5. Operating Capacity Comment : The maximum throughput rate corresponds to use of No. 2 fuel oil for 8760 hours/year (natural gas not available). When n.g. is available, No.2 fuel oil firing limited to 1000 hours/year.		

Emissions Unit Operating Schedule

Requested Maximum Operating Schedule :		
	24 hours/day	7 days/week
	52 weeks/year	8,760 hours/year

D. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank (700,000 gal) No. 2

Rule Applicability Analysis

N/A

List of Applicable Regulations

See Appendix LL for list of applicable regulations.

E. EMISSION POINT (STACK/VENT) INFORMATION

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank (700,000 gal) No. 2

Emission Point Description and Type :

1. Identification of Point on Plot Plan or Flow Diagram : S-5		
2. Emission Point Type Code : 1		
3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking : (limit to 100 characters per point) The emission point for a vertical fixed roof storage tank is the breather valve on the dome roof.		
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common : The are two types of emissions associated with the breather valve of a vertical fixed roof storage tank as described below. 1) Storage Loss: Emissions resulting from the expulsion of vapor from a tank through vapor expansion and contraction which are the result of changes in ambient temperature and barometric pressure. (Also known as standing loss) 2) Working Loss: Emissions resulting from the filling and emptying of the storage tank which are associated with the change in liquid level within the tank.		
5. Discharge Type Code :	P	
6. Stack Height :		feet
7. Exit Diameter :		feet
8. Exit Temperature :	77	°F
9. Actual Volumetric Flow Rate :		acfm
10. Percent Water Vapor :		%
11. Maximum Dry Standard Flow Rate :		dscfm
12. Nonstack Emission Point Height :	44	feet
13. Emission Point UTM Coordinates :		

Zone :	17	East (km) :	447.690	North (km) :	3127.560

14. Emission Point Comment :

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank (700,000 gal) No. 2

Segment Description and Rate : Segment 1

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Storage Loss: Emissions resulting from the expulsion of vapor from a tank through vapor expansion and contraction which are the result of changes in ambient temperature and barometric pressure (also known as standing loss or breathing loss).	
2. Source Classification Code (SCC) : 4-03-010-19	
3. SCC Units : Thousand Gallons Stored	
4. Maximum Hourly Rate :	5. Maximum Annual Rate :
6. Estimated Annual Activity Factor : 700.00	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment :	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank (700,000 gal) No. 2

Segment Description and Rate : Segment 2

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Working Loss: Emissions resulting from the filling and emptying of the storage tank which are associated with the change in liquid level within the tank. This segment assumes a natural gas curtailment. Accordingly, No. 2 distillate fuel oil would be used for the entire year (i.e., 8760 hours per year).	
2. Source Classification Code (SCC) : 4-03-010-21	
3. SCC Units : Thousand Gallons Transferred or Handled	
4. Maximum Hourly Rate :	5. Maximum Annual Rate :
6. Estimated Annual Activity Factor : 58,100.00	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment :	

F. SEGMENT (PROCESS/FUEL) INFORMATION

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank (700,000 gal) No. 2

Segment Description and Rate : Segment 3

1. Segment Description (Process/Fuel Type and Associated Operating Method/Mode) : Working Loss: Emissions resulting from the filling and emptying of the storage tank which are associated with the change in liquid level within the tank. This segment assumes natural gas is available. Accordingly, No. 2 distillate fuel oil use would be limited to 1000 hours per year	
2. Source Classification Code (SCC) : 4-03-010-21	
3. SCC Units : Thousand Gallons Transferred or Handled	
4. Maximum Hourly Rate :	5. Maximum Annual Rate :
6. Estimated Annual Activity Factor : 6,632.00	
7. Maximum Percent Sulfur :	8. Maximum Percent Ash :
9. Million Btu per SCC Unit :	
10. Segment Comment :	

G. EMISSIONS UNIT POLLUTANTS
(Regulated and Unregulated Emissions Units)

Emissions Unit Information Section 4
Distillate Fuel Oil Storage Tank (700,000 gal) No. 2

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

H. EMISSIONS UNIT POLLUTANT DETAIL INFORMATION
(Regulated Emissions Units Only - Emissions Limited Pollutants Only)

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank (700,000 gal) No. 2

Pollutant Potential/Estimated Emissions : Pollutant 1

1. Pollutant Emitted : **VOC**				
2. Total Percent Efficiency of Control :		%		
3. Potential Emissions :	0.12	lb/hour	0.52	tons/year
4. Synthetically Limited? [ ] Yes [X] No				
5. Range of Estimated Fugitive/Other Emissions:			to	tons/year
6. Emissions Factor : Reference : TANKS 2.0				
7. Emissions Method Code : 3				
8. Calculations of Emissions : Emission calculations are based on USEPA's TANKS Version 2.0 program (January, 1995) which include both breathing and working loss emissions. The lb/hour emission factor is estimated based on the annual emission factor obtained from TANKS (assumes 8,760 hours/year). See Appendix MM for TANKS output report.				
9. Pollutant Potential/Estimated Emissions Comment : Maximum estimated emissions based on No. 2 distillate fuel oil firing for an entire year in the event natural gas is unavailable.				

Emissions Unit Information Section 4
Distillate Fuel Oil Storage Tank (700,000 gal) No. 2

Pollutant Information Section 1

Allowable Emissions 1

1. Basis for Allowable Emissions Code : RULE
2. Future Effective Date of Allowable Emissions :
3. Requested Allowable Emissions and Units :
4. Equivalent Allowable Emissions : lb/hour tons/year
5. Method of Compliance : As specified in 40 CFR 60.116 (a) and (b), Subpart Kb.
6. Pollutant Allowable Emissions Comment (Desc. of Related Operating Method/Mode) : RULE: 40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construcion, Reconstruction, or Modification Commenced after July 23, 1984.

K. PREVENTION OF SIGNIFICANT DETERIORATION (PSD) INCREMENT TRACKING INFORMATION

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank (700,000 gal) No. 2

PSD Increment Consumption Determination

1. Increment Consuming for Particulate Matter or Sulfur Dioxide?

[ ] The emissions unit is undergoing PSD review as part of this application, or has undergone PSD review previously, for particulate matter or sulfur dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after January 6, 1975. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emissions unit began initial operation after January 6, 1975, but before December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after December 27, 1977. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, the baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

2. Increment Consuming for Nitrogen Dioxide?

[ ] The emissions unit addressed in this section is undergoing PSD review as part of this application, or has undergone PSD review previously, for nitrogen dioxide. If so, emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source pursuant to paragraph (c) of the definition of "major source of air pollution" in Chapter 62-213, F.A.C., and the emissions unit addressed in this section commenced (or will commence) construction after February 8, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] The facility addressed in this application is classified as an EPA major source, and the emission unit began initial operation after February 8, 1988, but before March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] For any facility, the emissions unit began (or will begin) initial operation after March 28, 1988. If so, baseline emissions are zero, and emissions unit consumes increment.

[ ] None of the above apply. If so, baseline emissions of the emissions unit are nonzero. In such case, additional analysis, beyond the scope of this application, is needed to determine whether changes in emissions have occurred (or will occur) after the baseline date that may consume or expand increment.

3. Increment Consuming/Expanding Code :		
PM :	SO2 :	NO2 :
4. Baseline Emissions :		
PM :	lb/hour	tons/year
SO2 :	lb/hour	tons/year
NO2 :		tons/year
5. PSD Comment :		
Tank does not emit PSD increment consuming pollutants.		

L. EMISSIONS UNIT SUPPLEMENTAL INFORMATION

Emissions Unit Information Section 4

Distillate Fuel Oil Storage Tank (700,000 gal) No. 2

Supplemental Requirements for All Applications

1. Process Flow Diagram :	Appendix JJ
2. Fuel Analysis or Specification :	NA
3. Detailed Description of Control Equipment :	NA
4. Description of Stack Sampling Facilities :	NA
5. Compliance Test Report :	NA
6. Procedures for Startup and Shutdown :	NA
7. Operation and Maintenance Plan :	NA
8. Supplemental Information for Construction Permit Application :	NA
9. Other Information Required by Rule or Statue :	NA

Additional Supplemental Requirements for Category I Applications Only

10. Alternative Methods of Operations :	Appendix KK
11. Alterntive Modes of Operation (Emissions Trading) :	NA

12. Identification of Additional Applicable Requirements :	Appendix LL
13. Compliance Assurance Monitoring Plan :	NA

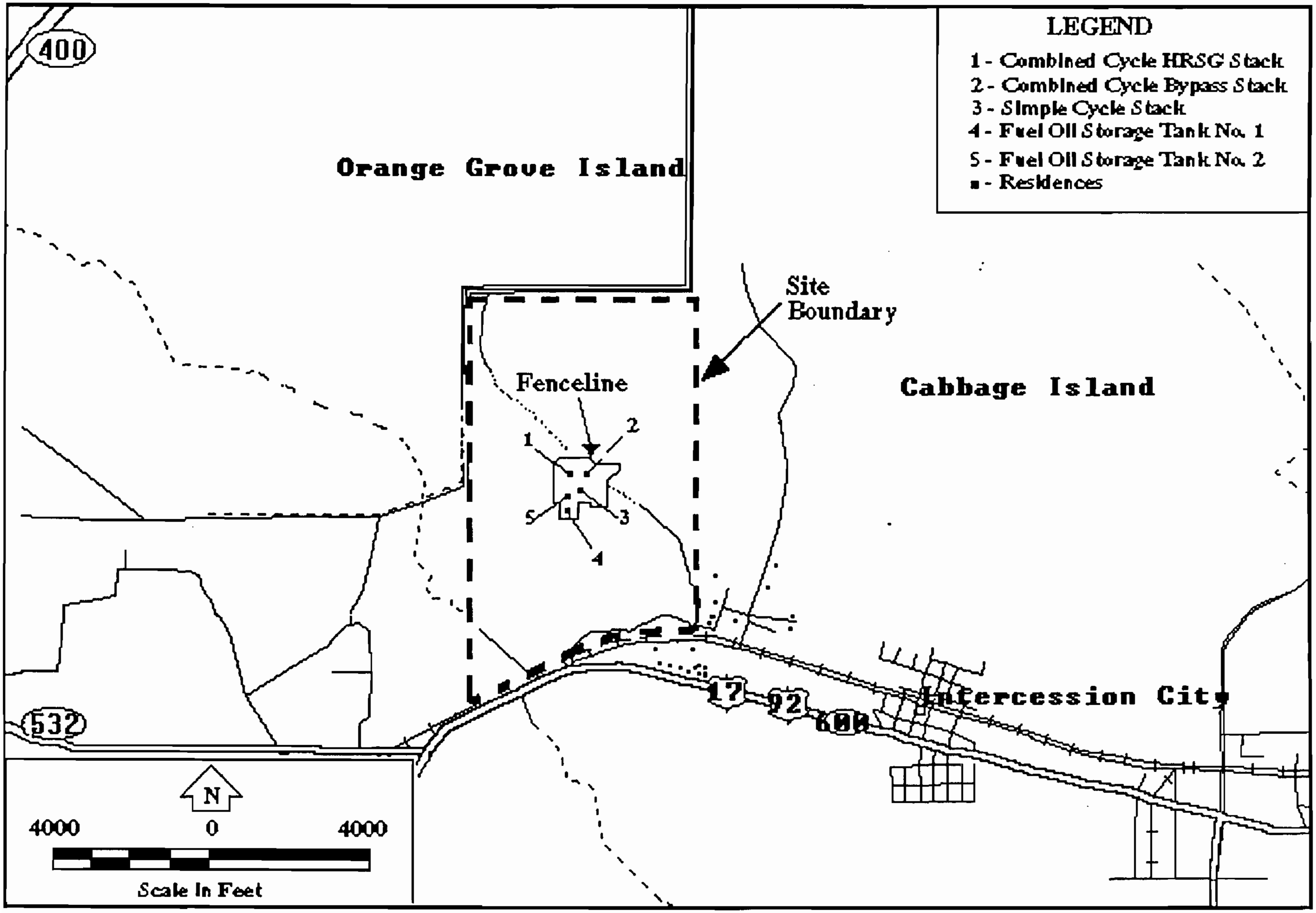
14. Acid Rain Application (Hard-copy Required) :

NA	Acid Rain Part - Phase II (Form No. 62-210.900(1)(a))
NA	Repowering Extension Plan (Form No. 62-210.900(1)(a)1.)
NA	New Unit Exemption (Form No. 62-210.900(1)(a)2.)
NA	Retired Unit Exemption (Form No. 62-210.900(1)(a)3.)

Appendix A

Appendix A

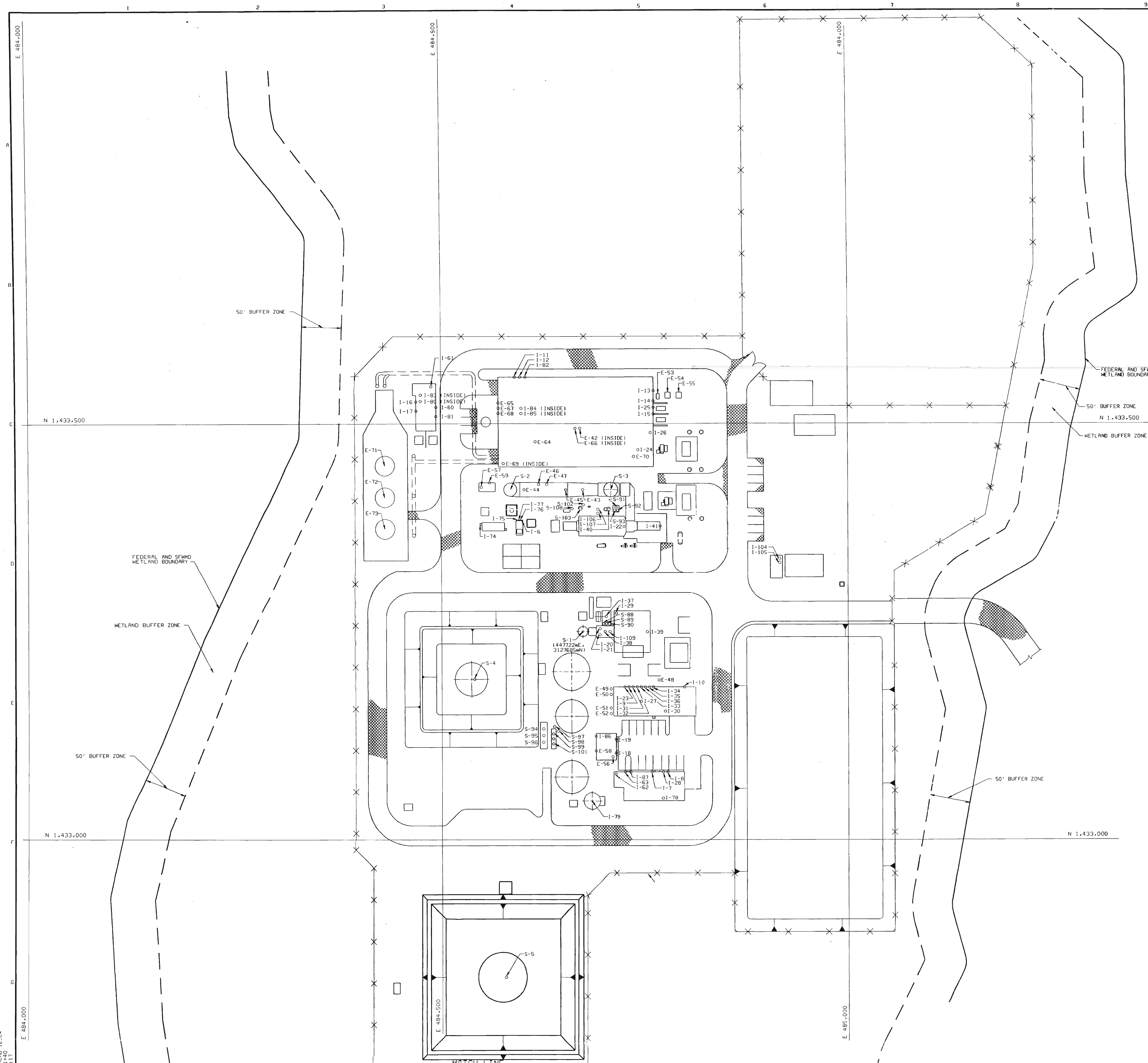
Area Map Showing Facility Location


LEGEND
1 - Combined Cycle HRSG Stack
2 - Combined Cycle Bypass Stack
3 - Simple Cycle Stack
4 - Fuel Oil Storage Tank No. 1
5 - Fuel Oil Storage Tank No. 2
▪ - Residences
400
Orange Grove Island
Site
Boundary
Cabbage Island
Fenceline
1
2
3
4
5
532
17
92
600
Intercession City
N
4000
0
4000
Scale In Feet

Appendix B

Appendix B

Facility Plot Plan



EMISSION ID	NUMBER	EMISSION SOURCE DESCRIPTION
S	1	SCCT STACK
S	2	CCCT HRSG STACK
S	3	CCCT BYPASS STACK
S	4	#1 FUEL OIL STORAGE TANK VENT
S	5	#2 FUEL OIL STORAGE TANK VENT
I	6	WATER WASH SKID BUILDING EXHAUST FAN
I	7	WATER TREATMENT BUILDING - BUILDING EXHAUST FAN
I	8	WATER TREATMENT BUILDING - BUILDING EXHAUST FAN
I	9	PLANT SERVICES BUILDING - BUILDING EXHAUST FAN
I	10	PLANT SERVICES BUILDING - BUILDING EXHAUST FAN
I	11	GENERATION BUILDING - BUILDING EXHAUST FAN
I	12	GENERATION BUILDING - BUILDING EXHAUST FAN
I	13	GENERATION BUILDING - BUILDING EXHAUST FAN
I	14	GENERATION BUILDING - BUILDING EXHAUST FAN
I	15	GENERATION BUILDING - BUILDING EXHAUST FAN
I	16	CHEMICAL FEED BUILDING - BUILDING EXHAUST FAN
I	17	CHEMICAL FEED BUILDING - BUILDING EXHAUST FAN
I	18	FIRE WATER PUMP BUILDING - BUILDING EXHAUST FAN
I	19	FIRE WATER PUMP BUILDING - BUILDING EXHAUST FAN
I	20	SCCT COMPARTMENT VENTILATION EXHAUST FAN
I	21	SCCT COMPARTMENT VENTILATION EXHAUST FAN
I	22	CCCT COMPARTMENT EXHAUST FAN
I	23	PLANT SERVICES BUILDING RESTROOM EXHAUST VENT
I	24	GENERATION BUILDING LAB SINK SANITARY SEWER VENT
I	25	GENERATION BUILDING KITCHEN SANITARY SEWER VENT
I	26	GENERATION BUILDING RESTROOM SANITARY SEWER VENT
I	27	COMPRESSED AIR STORAGE TANK RELIEF VENT
I	28	WATER PRESSURIZER TANK EXHAUST VENT
I	29	SCCT INSTRUMENT CONTROL COMPRESSED AIR TANK VENT
I	30	AIR COMPRESSOR INTAKE/EXHAUST
I	31	AIR COMPRESSOR AIR DRYER EXHAUST VENT
I	32	AIR COMPRESSOR AIR DRYER EXHAUST VENT
I	33	AIR COMPRESSOR AIR DRYER EXHAUST VENT
I	34	AIR COMPRESSOR AIR DRYER EXHAUST VENT
I	35	AIR COMPRESSOR AIR DRYER EXHAUST VENT
I	36	AIR COMPRESSOR AIR DRYER EXHAUST VENT
I	37	SCCT LUBE OIL VAPOR EXTRACTOR VENT
I	38	SCCT LUBE OIL MIST ELIMINATOR VENT
I	39	SCCT GENERATOR LUBE OIL MIST ELIMINATOR VENT
I	40	CCCT LUBE OIL MIST ELIMINATOR VENT
I	41	CCCT GENERATOR LUBE OIL MIST ELIMINATOR VENT
E	42	STEAM TURBINE LUBE OIL VAPOR EXTRACTOR
E	43	MAIN STEAM SAFETY RELIEF VENT
E	44	LP STEAM DRUM SAFTEY RELIEF
E	45	MAIN STEAM DRUM SAFETY RELIEF VENT
E	46	IP STEAM DRUM SAFETY RELIEF VENT
E	47	IP STEAM DRUM SAFETY RELIEF VENT
E	48	PLANT SERVICES BUILDING A/C UNIT
E	49	PLANT SERVICES BUILDING A/C UNIT
E	50	PLANT SERVICES BUILDING A/C UNIT
E	51	PLANT SERVICES BUILDING A/C UNIT
E	52	PLANT SERVICES BUILDING A/C UNIT
E	53	GENERATION BUILDING A/C UNIT
E	54	GENERATION BUILDING A/C UNIT
E	55	GENERATION BUILDING A/C UNIT
E	56	#1 DIESEL FIRE PUMP EXHAUST STACK
E	57	#2 DIESEL FIRE PUMP EXHAUST STACK
E	58	#1 FIRE PUMP DIESEL STORAGE TANK VENT
E	59	#2 FIRE PUMP DIESEL STORAGE TANK VENT
I	60	#2 SULFURIC ACID STORAGE TANK FILLING GAS VENT
I	61	#2 SULFURIC ACID STORAGE TANK OVER-PRESSURE RELIEF VENT
I	62	#1 SULFURIC ACID STORAGE TANK OVER-PRESSURE RELIEF VENT
I	63	#1 SULFURIC ACID STORAGE TANK FILLING GAS VENT
E	64	STEAM BLOWDOWN EXHAUST VENT
E	65	STEAM SEAL EXHAUST VENT
E	66	STEAM TURBINE CONDENSER AIR VENT
E	67	VACUUM AIR EXTRACTOR VENTS
E	68	VACUUM AIR EXTRACTOR VENTS
E	69	PORTABLE WELDING RIG (ACETYLENE AND OXYGEN)
E	70	GENERATION BUILDING LAB HOOD VENT
E	71	COOLING TOWER CELL EXHAUST PORT
E	72	COOLING TOWER CELL EXHAUST PORT
E	73	COOLING TOWER CELL EXHAUST PORT
I	74	WATER INJECTION SKID WATER INJECTION STORAGE TANK VENT
I	75	WATER WASH SKID STORAGE TANK VENT
I	76	WATER WASH SKID WATER STORAGE TANK VENT
I	77	WATER WASH SKID SOAP STORAGE TANK VENT
I	78	DEGASSER EXHAUST VENT
I	79	NEUTRALIZATION BASIN
I	80	ACRYLIC POLYMER STORAGE TANK
I	81	SODIUM HYPOCHLORIDE STORAGE TANK VENT
S	82	HYDRAZINE STORAGE TANK VENT
I	83	METHYLENE-BIS-THIOCYANATE STORAGE TANK
I	84	MORPHOLINE SOLUTION STORAGE TANK
I	85	TETRAPOTASSIUM PYROPHOSPHATE STORAGE TANK
I	86	CALCIUM HYPOCHLORITE STORAGE TANK
I	87	SODIUM HYDROXIDE STORAGE TANK
S	88	SCCT FUEL PURGE VENT
S	89	SCCT FUEL PURGE VENT
S	90	SCCT FUEL PURGE VENT
S	91	NATURAL GAS VALVE MODULE VENT
S	92	NATURAL GAS VALVE MODULE VENT
S	93	NATURAL GAS VALVE MODULE VENT
S	94	OIL/WATER SEPARATOR TANK VENT
S	95	OIL/WATER SEPARATOR TANK VENT
S	96	OIL/WATER SEPARATOR TANK VENT
S	97	OIL/WATER SEPARATOR TANK VENT
S	98	OIL/WATER SEPARATOR TANK VENT
S	99	OIL/WATER SEPARATOR TANK VENT
S	100	OIL/WATER SEPARATOR TANK VENT
S	101	OIL/WATER SEPARATOR TANK VENT
S	102	NATURAL GAS FUEL SCRUBBER VENT
S	103	NATURAL GAS FUEL SCRUBBER VENT
I	104	NATURAL GAS COMPRESSOR STATION HIGH PRESSURE RELIEF
I	105	NATURAL GAS COMPRESSOR STATION HIGH PRESSURE RELIEF VENT
I	106	NATURAL GAS FILTER SAFETY RELIEF VENT
I	107	NATURAL GAS FILTER SAFETY RELIEF VENT
S	108	CCCT NATURAL GAS FUEL GAS SCRUBBER DRAIN TANK VENT
I	109	SCCT COMPRESSED AIR VARIABLE BLEED VALVE EXHAUST

NO.	DATE	REVISIONS AND RECORD OF ISSUE	BY	CHK	APP	FLM
0	12-08-92	PERMIT ISSUE	SSJ		SRJ	

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA

SIGNED STEPHEN R. [illegible]
DATE 12-08-92 REG NO. 45681

BLACK & VEATCH

ENGINEER | DRAWN | CHECKED | DATE

KISSIMMEE UTILITY AUTHORITY
CANE ISLAND COMBUSTION TURBINE

SITE ARRANGEMENT

PROJECT / DRAWING NUMBER: 26741-FIGURE-1
REV: A
CODE
AREA

Appendix C

Appendix C

Process Flow Diagrams
(See individual unit process flow diagrams, Appendices N, Y and GG)

Appendix D

Appendix D

Precautions to Prevent Emissions of Unconfined Particulate Matter

Precautions to Prevent Emissions of Unconfined Particulate Matter

Facility Supplemental Information

Unconfined Particulate Matter Source	Precautions to Prevent and Control Unconfined Particulate Matter Emissions
Worker vehicle movements on-site	Paved roads and parking areas
Delivery vehicles (i.e., chemicals, fuel oil, consumable, trash, etc.)	Paved roads and parking areas

Appendix E

Appendix E

Fugitive Emissions Identification

Fugitive Emissions Identification

Facility Supplemental Information

Fugitive Emission Source	Manner by which these fugitive emissions are addressed in this application
Worker and site vehicle movements on-paved roads	Total fugitive emissions (unconfined particulate matter) as the result of on-site vehicular traffic are estimated to be 0.005 tpy (see Appendix FF calculation sheet). Therefore, fugitive emissions are not required to be reported in accordance with Subsection III of the permit application instructions.
Delivery vehicles movements on-paved roads	
Fuel oil delivery by truck on paved roads	

Appendix F

Appendix F

List of Insignificant Activities

List of Insignificant Activities

Facility Supplemental Information

Insignificant or Exempt Source Description	Justification	Emission Source Id
Building HVAC exhaust vents	These emission sources are atmospheric ventilation systems which are automatically or manually operated to circulate air. These vents are not designed to remove air pollutants or exhaust from other sources and are therefore considered insignificant. Guidance for this justification is found in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-6 through I-19
Turbine compartment ventilation exhaust vents	Both the LM6000 and the PG7111EA combustion turbine compartments contain operating equipment compartment exhaust vents. Emissions from these vents may contain VOCs from the turbine lube oils. However, the VOC emissions associated with these sources are negligible. Guidance for this justification is found in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-20 through I-22

Sanitary sewer vents	Atmospheric vents are included in the kitchen and restrooms located throughout the facility. The vents are used to allow air circulation throughout the system. Emissions from these sources are considered insignificant/exempt. Guidance for this justification is found in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-23 through I-26
Compressed air systems	Compressed air systems are used throughout the facility for water pressurization, instrument control, maintenance activities, etc. Sources from these systems include compressed air storage tank relief vents and air compressor/air dryer exhaust vents. Emissions from these vents consist of air and contain no reportable pollutants. Guidance for this justification is found in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-27 through I-36
Turbine lube oil vapor extractors and lube oil mist eliminator vents	Atmospheric vents are provided in the turbine lube oil system to enable removal of water vapor and lube oil vapor/mist from the lube oil system for the turbine and generator bearings and to enable atmospheric pressure operation of the lube oil storage tanks. These vents are an insignificant source of VOC. Guidance for this justification is found in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-37 through I-42

Steam drum safety relief valve vents	Safety relief valve vents are provided on the main, intermediate, and low pressure steam drum systems. The relief valves are utilized only during turbine upset conditions to prevent overpressurization. The emissions associated with these vents will consist of pure water vapor and steam, with no reportable pollutants in the exhaust stream. Guidance for this justification is found in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-43 through I-47
Building air conditioning units	Several air conditioning units are provided at the facility for purposes of climate control and general circulation. Each unit contains less than 50 lbs of charge of any Class I or Class II ozone-depleting substance regulated under Title VI. Additionally, Guidance in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants lists heating, ventilation, and air conditioning systems as rule exempt.	E-48 through E-55
Diesel fire pump exhaust stacks	The facility's two diesel fire pumps are equipped with exhaust stacks to enable the safe release of the combustion exhaust gases from the fire water pump buildings. These sources are exempt as fire and safety equipment under Rule 62-210.300(3).	E-56 through E-57

Diesel fire pump diesel storage tank vents	An atmospheric vent is provided on the diesel fire pump diesel storage tank to safely purge air and diesel vapors from within. The vent operates intermediately, discharging during diesel fire pump start up and shutdown and when the tank is being filled. These sources are exempt as fire and safety equipment under Rule 62-210.300(3).	E-58 through E-59
Sulfuric acid storage tank vents	Two sulfuric acid storage tanks are included as part of the circulating water treatment system. Sulfuric acid is stored in the tank and used for acid treatment of the water to control the pH level. The tanks are equipped with vents to exhaust air during periods when the tanks are being filled or in the event of overpressurization. Sulfuric acid is not considered a HAP or a Title III 112(r) substance. Additionally, due to the low vapor pressure of sulfuric acid, emissions from these source are expected to be extremely low and infrequent.	I-60 through I-63
Various steam release vents	Atmospheric vents are provided for various types of steam releases including relief vents for pressure buildup in extraction steam lines, steam seal exhaust vents, steam turbine condenser air vents, condenser vacuum air extractors, and steam generator blowdown exhaust. Emissions from these sources will consist of steam with no reportable emissions. Therefore, these sources are considered exempt.	E-64 through E-68
Welding equipment	These sources are exempt under Rule 62-210.300(3).	E-69

Lab hood vent	These sources are exempt under Rule 62-210.300(3).	E-70
Cooling Tower	A 3 cell linear mechanical draft freshwater cooling tower is used to dissipate heat from the circulating water to the atmosphere. These sources are considered insignificant in accordance with guidance in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-71 through I-73
Water injection storage tank vent	The facility utilizes water injection as a means of NO_x emission controls. The water is stored in a tank prior to injection into the combustion turbine. The tank is equipped with a vent to exhaust air during periods when the tanks are being filled or discharged. Emissions from this vent consists of air/water vapor and contain no reportable pollutants.	I-74
Water wash system storage tank vents	Water wash system is an on-line system designed to periodically wash combustion turbine blades. The system includes storage tanks for water, soap detergent, and a soap detergent/water solution.	I-75 through I-77
Demineralized water degasser exhaust vent	Demin water degasser for removal of CO_2 is classified as an insignificant source. Guidance for this justification is found in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-78

Neutralization basin	The neutralization basin is a 30,000 gallon below grade, acid resistant brick lined detention basin. It serves a central drainage point for several 6 inch curbed chemical storage containment areas throughout the facility. Under normal conditions, the neutralization basin results in no reportable emissions and is therefore considered exempt. Guidance for this justification is found in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-79
Acrylic Polymer storage tank	Storage and use of this substance is in closed containers and is solely for the purpose of water treatment. The substance is not considered a HAP, or subject to Title III 112(r). Accordingly, emissions from this source are considered insignificant. Guidance for this justification is found in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-80
Sodium Hypochloride storage tank	Storage and use of this substance is in closed containers and is solely for the purpose of water treatment. The substance is not considered a HAP, or subject to Title III 112(r). Accordingly, emissions from this source are considered insignificant. Guidance for this justification is found in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-81

Hydrazine storage tank vent	Hydrazine is used in the boiler feed water treatment system. Hydrazine is considered a HAP and is listed as a Title III 112(r) chemical. However, an insignificant amount is actually used and stored on-site. Annual emissions of hydrazine are expected to be less than 0.02 tpy. Hydrazine emission calculations are include in Appendix MM, and have been included in the total facility HAPS calculation.	S-82
Methylene-bis-thiocyanate storage tank	Storage and use of this substance is in closed containers and is solely for the purpose of water treatment. The substance is not considered a HAP, or subject to Title III 112(r). Accordingly, emissions from this source are considered insignificant. Guidance for this justification is found in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-83
Morpholine solution storage tank	Storage and use of this substance is in closed containers and is solely for the purpose of water treatment. The substance is not considered a HAP, or subject to Title III 112(r). Accordingly, emissions from this source are considered insignificant. Guidance for this justification is found in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-84

Tetrapotassium Pyrophosphate storage tank	Storage and use of this substance is in closed containers and is solely for the purpose of water treatment. The substance is not considered a HAP, or subject to Title III 112(r). Accordingly, emissions from this source are considered insignificant. Guidance for this justification is found in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-85
Calcium Hypochlorite storage tank	Storage and use of this substance is in closed containers and is solely for the purpose of water treatment. The substance is not considered a HAP, or subject to Title III 112(r). Accordingly, emissions from this source are considered insignificant. Guidance for this justification is found in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-86
Sodium Hydroxide storage tank	Storage and use of this substance is in closed containers and is solely for the purpose of water treatment. The substance is not considered a HAP, or subject to Title III 112(r). Accordingly, emissions from this source are considered insignificant. Guidance for this justification is found in FDEP's March 25, 1994 letter to the Florida Power and Light Company regarding insignificant sources at electric power plants.	I-87
SCCT fuel purge vents	Insignificant emissions are anticipated from the fuel purge vents.	S-88 through S-90

Natural gas line/processing vents	Insignificant emissions are anticipated from the natural gas line processing vents. See **Appendix MM** for calculations. Total miscellaneous sources of VOC emissions emit less than 5 tpy and are therefore exempt in accordance with Rule 62-213.420(3)(c)(3)(a).	S-91 through S93 S-102, S-103 and S-106 through S-108
Natural gas compressor station high pressure relief vents	Natural gas compressor station high pressure relief vents are provided to safely discharge natural gas away for workers and combustion sources in the event of an emergency or malfunction resulting from a high pressure situation. These vents are not continuously operating sources and are installed only as a safety precaution. Therefore, these sources are considered insignificant due to low pollutant emissions.	I-104 and I-105
Oil/Water separator waste oil collection tank vents	An underground waste oil collection tank is provided in the facility's drain system. In the infrequent event when an oil leak or spill occurs, the oil is directed into the drain system for storage in the waste oil collection tank. Vents are provided on the tank to allow air to escape from within the tank. This is not a continuously operating source and emissions are insignificant. See **Appendix MM** for calculations. Total miscellaneous sources of VOC emissions emit less than 5 tpy and are therefore exempt in accordance with Rule 62-213.420(3)(c)(3)(a).	S-94 through S-101

SCCT compressed air variable bleed exhaust valve	When the turbine is operating at loads less than design load, compressed intake combustion air is throttled or choked, with the unused portion vented to the atmosphere. Emissions from this vent consists of air and contain no reportable pollutants.	I-109

Appendix G

Appendix G

List of Equipment/Activities Regulated Under Title VI

List of Equipment/Activities Regulated Under Title VI

Facility Supplemental Information

There are 8 building air conditioning units (see Appendix F, insignificant source list, source ID numbers E-48 through E-55) at the facility that utilized R-22 as their coolant charge. R-22 is listed as a Class II substance regulated under Title VI. However, each air conditioning unit contains less than 50 lbs of charge. Additionally, FDEP's May 20, 1994 letter regarding insignificant sources at electric power plants identifies heating, ventilation, and air conditioning systems (HVAC) as being rule exempt sources.

The following table identifies the building air conditioning units' manufacturer, model, and amount of R-22 charge for reference purposes.

Location	Air Conditioner	Emission Source ID
Plant services building air conditioning units	- 4 Mitsubishi Model PUH36EK, with 10 lbs 9 oz R-22 charge each. - 1 Trane Model TTAO72C400AO, with 13 lbs R-22 charge.	E-48 through E-51 E-52
Generation building air conditioning units	3 Trane Model RAUCC304BJ13ADF1, with 40 lbs R-22 charge each.	E-53 through E-55
Various window air conditioning units which were not individually defined.	Much less than 50 lbs charge.	N/A

Appendix H

Appendix H

Alternative Methods of Operation

Alternative Methods of Operation

The combustion turbine facility will burn natural gas as the primary fuel and No. 2 distillate fuel oil (0.05 percent sulfur) as a secondary back-up fuel. In the event of non-availability of natural gas (natural gas curtailment), the facility may burn No. 2 distillate fuel oil the entire year, or up to 1,000 hours per year if natural gas is available (with the remainder of the year on natural gas).

As provided for in the permit application instructions (Ref. DEP Form No. 62-210.900(1), page 20), the alternative methods of operation as the result of fuel options are discussed in detail in the Emissions Unit Information Section of the permit application.

Appendix I

Appendix I

Facility Applicable Requirements

Facility Applicable Requirements

Applicable Regulation	Applicable Requirement	Compliance Status
40 CFR 60.7, Notification and record keeping	Any physical or operational change to an existing facility which may increase the emission of any air pollutant requires notification pursuant to this rule, postmarked 60 days before the change is commenced.	Will comply when applicable
	An excess emissions and monitoring systems performance report shall be submitted semiannually. The facility shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of the facility; any malfunction of the air pollution control equipment; or any period the CEMS is inoperable	Comply
	The owner or operator of an affected facility shall maintain a file of CEMS and performance test measurements, evaluations, and calibration checks for two years following the date of such activity.	Comply
40 CFR 60.8 (d), Testing	Notify the Administrator of any performance test at least 30 days prior to the test.	Comply
40 CFR 60.8(e), Testing	Provide sampling ports, safe sampling platform, utilities and testing equipment prior to stack test.	Comply

40 CFR 60.13, Monitoring Requirements	For CEMS subject to this part, the owner or operator shall check the zero and span calibration drifts at least once daily. The zero and span shall be adjusted whenever the 24-hour zero drift or span drift exceeds two times the limits of the performance specification.	Comply
40 CFR 61.5, Prohibited activities	Ninety days after the effective date of any standard pursuant to this part, no owner or operator shall operate any existing source subject to that standard in violation of the standard.	Will comply when applicable
40 CFR 72.9, Standard requirements	A complete Acid Rain permit application shall be submitted for the affected facility by January 1, 1998.	Will comply when applicable
40 CFR 72.21, Submissions	Each submission under the Acid Rain program shall be submitted, signed, and certified by the designated representative.	Will comply when applicable
40 CFR 72.90, Annual compliance certification report	Sixty days after the end of the calendar year, the designated representative shall submit an annual compliance certification report for each affected unit.	Comply
40 CFR 75.3, Compliance dates	Gas or oil fired Acid Rain affected units commencing operation after Nov. 15, 1990 which are not located in an ozone nonattainment area or the ozone transport region shall complete all NOx and CO2 CEMS certification tests by Jan. 1, 1996.	Comply

40 CFR 75.5, Prohibitions	No owner or operator of an affected Acid Rain unit shall operate the unit without complying with the requirements of 40 CFR 75.2 through 40 CFR 75.67 and appendices A through I of Part 75.	Comply (see unit specific compliance plan)
F.A.C. 62-4.030, General Prohibition	Any stationary installation which will be a source of air pollution shall not be operated, maintained, constructed, expanded, or modified without appropriate and valid permits issued by the DEP.	Will comply when applicable
F.A.C. 62-4.090, Renewals	Submit an operating permit renewal application to the FDEP 180 days before the expiration of the operating permit.	Will comply when applicable
F.A.C. 62-4.130, Plant Operation - Problems	If a facility is temporarily unable to comply with any of the conditions of a permit due to breakdown of equipment or destruction by hazard of fire, wind, or by other cause, the permittee shall immediately notify the DEP.	Will comply when applicable
F.A.C. 62-4.160, Permit Conditions	The permittee shall allow authorized DEP personnel access to the facility where the permitted activity is located to have access to and copy any records that must be kept under conditions of the permit; inspect the facility, equipment, practices, or operations regulated or required under the permit; and sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with permit conditions.	Will comply when applicable

	If the permittee does not comply with or will be unable to comply with any condition or limitation of permit number AC 49-205703, the permittee shall immediately provide the DEP with a description of and cause of noncompliance; the period of noncompliance including dates and times, or, if not corrected, the anticipated time the noncompliance is expected to continue; and steps being taken to reduce, eliminate, and prevent recurrence of the noncompliance.	Will comply when applicable
	Permits, or a copy thereof, shall be kept at the work site of the permitted activity.	Comply
	The permittee shall furnish all records and plans required under DEP rules; hold at the facility all monitoring information, reports, and records of data for at least three years from the date of the sample, measurement, report, or application.	Comply
F.A.C. 62-4.160, Permit Conditions (continued)	When requested by DEP, the permittee shall furnish, within a reasonable time, any information required by law which is needed to determine compliance with any permit.	Will comply when applicable
F.A.C. 62-4.210, Construction Permits	No person shall construct any installation or facility which will reasonably be expected to be a source of air pollution without first applying for and receiving a construction permit from the DEP unless exempted by statute or DEP rule.	Will comply when applicable

F.A.C. 62-210.300, Permits Required	An air construction permit shall be obtained by the owner or operator of any proposed new or modified facility or emissions unit prior to the beginning of construction or modification.	Will comply when applicable
F.A.C. 62-210.350, Public Notice and Comment	A notice of proposed agency action on a permit application as described in F.A.C. 62-210.350(1)(a), where the proposed agency action is to issue the permit, shall be published by the applicant.	Will comply when applicable
F.A.C. 62-210.360, Administrative Permit Corrections	A facility owner shall notify the DEP by letter of minor corrections to information contained in a permit. For operating permits, a copy shall be provided to the EPA.	Will comply when applicable
F.A.C. 62-210.370, Reports	An Annual Operating Report for Air Pollutant Emitting Facility (DEP Form No. 62-210.900(5)) shall be completed each year for all Title V sources. The annual operating report shall be submitted by March 1 of the following year.	Comply
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.	Comply
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130	Will comply when applicable

F.A.C. 62-213.205, Annual Emissions Fee	Each Title V source must pay an annual emissions fee between January 15 and March 1 based on the factors identified in this rule.	Comply
F.A.C. 62-213.420, Permit Applications	Each Title V Acid Rain source that commenced operation on or before October 25, 1995 shall submit a operating permit application by June 15, 1996.	Comply
F.A.C. 62-214.320, Applications	New acid rain sources must submit an Acid Rain Part application in accordance with the provisions of 40 CFR Part 72.	Will comply when applicable
F.A.C. 62-273.400, Air Pollution Episodes	Upon a declaration that an air pollution episode level exists (alert, warning, or emergency), any person responsible for the operation or conduct of activities which result in emission of air pollutants shall take actions as required in F.A.C. 62-273.400, 62-273.500, and 62-273.600.	Will comply when applicable
F.A.C. 62-273.400, Air Alert	Upon a declaration of an air alert, open burning will be prohibited and motor vehicle operation minimized.	Will comply when applicable
F.A.C. 62-273.500, Air Warning	Upon a declaration of an air warning, open burning will be prohibited and motor vehicle operation minimized. In addition, unnecessary space heating/cooling is prohibited.	Will comply when applicable

F.A.C. 62-273.600, Air Emergency	Upon a declaration of an air warning, operations will be restricted as prescribed under 62-273.600.	Will comply when applicable
F.A.C. 62-296.320, General Pollutant Emission Limiting Standards	No person shall store, pump, handle, process, load, unload, or use in any process or installation, VOCs or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary by the DEP.	Comply
	No person shall cause, suffer, allow, or permit the discharge of air pollutants which cause or contribute to an objectionable odor.	Comply
	Open burning in connection with industrial, commercial, or municipal operations is prohibited except if an emergency exists which requires immediate action to protect human health and safety.	Comply
	No person shall cause, let, permit, suffer, or allow the emissions of unconfined particulate matter from any activity without taking reasonable precautions to prevent such emissions.	Comply
F.A.C. 62-296.405, Fossil Fuel Steam Generators with more than 250 MBtu/hour Heat Input	The test method for visible emissions shall be DEP Method 9 as incorporated in F.A.C. 62-297.	Comply
	The test method for particulate emissions shall be EPA Methods 17, 5, 5B, or 5F as incorporated in F.A.C. 62-297	Comply

F.A.C. 62-296.405, Fossil Fuel Steam Generators with more than 250 MBtu/hour Heat Input (continued)	The test method for sulfur dioxide emissions shall be DEP Methods 6, 6A, 6B, or 6C as incorporated in F.A.C. 62-297. Fuel sampling and analysis may be used as an alternate sampling procedure if such a procedure is incorporated in the operation permit for the emissions unit.	Comply
	Each owner or operator of an emission unit subject to this rule shall install, calibrate, operate, and maintain a continuous monitoring system according to the requirements of 40 CFR 51, Appendix P and 40 CFR 60, Appendix B.	Comply
F.A.C. 62-297.310, General Test Requirements	Compliance tests for mass emission limitations shall consist of three complete and separate determinations of the total air pollutant emission rate, and three complete and separate determinations of any applicable process variables according to the test procedures delineated in this rule.	Comply
Permit Number: AC 49-205703	The facility will comply with all operating restrictions, performance testing, and emission limits incorporated in the referenced permit.	Comply

Appendix J

Appendix J

Compliance Assurance Monitoring Plan

Compliance Assurance Monitoring Plan

Before the Clean Air Act was re-authorized in 1990, the Agency and State and local air pollution offices had concerns that some sources of air pollution were not in compliance with emission control regulations and, as a result, air quality was being adversely affected. Title VII, enforcement provisions, of the Clean Air Act Amendments of 1990 authorized the Agency to develop regulations requiring permitted facilities to monitor the adequacy of emission control equipment and operations. In September 1993, EPA proposed an enhanced monitoring rule, a new Part 64 to title 40 of the Code of Federal Regulations, that set general monitoring criteria to be followed in demonstrating continuous compliance.

In April 1995, the Agency determined to revisit the proposed Part 64 enhanced monitoring rule to allow review of other regulatory approaches to enhanced monitoring. The EPA received an extension of the court-ordered deadline until July 1, 1996, to allow time for stakeholder involvement in development of a new rule. The stakeholders currently involved in this process include industry representatives, State and local agencies, and environmental groups. The result of the process is a redrafted rule, named compliance assurance monitoring or CAM. The CAM rule is designed to satisfy the requirements for monitoring and compliance certification in titles V, the operating permits program, and title VII of the 1990 Clean Air Act Amendments.

The CAM rule reproposal date (originally scheduled for December 1995) and the promulgation date of July 1, 1996, will likely be delayed from 7 to 9 months as a result of the Agency dealing with the significant issues raised in the comments on the draft rule and the recent government shutdown.

Compliance monitoring will be conducted as detailed in the Emissions Unit Information portion of this application, and as required by construction permit AC49-205703. If, after the approval and promulgation of the CAM rule, more restrictive compliance monitoring is required, the necessary steps will be undertaken to ensure the facility meets all monitoring requirements.

Appendix K

Appendix K

Risk Management Plan Verification

Risk Management Plan Verification

The regulations [Risk Management Plan, pursuant to Section 112(r) of the Clean Air Act as amended in 1990] when promulgated, will require the owner/operator of a stationary source at which a regulated substance is present in more than a threshold quantity to prepare and implement a risk management plant to detect and prevent or minimize accidental releases of such substances from the stationary source, and to provide a prompt emergency response to any such releases in order to protect human health and the environment. The U.S. EPA promulgated the list of regulated substances and threshold quantities in the Federal Register on January 31, 1994, and proposed the risk management plan regulation on October 20, 1993. The regulations, when promulgated, will be applicable to a stationary source three years after the date of promulgation of the risk management plan regulations, or three years after the date on which a regulated substance present at the source in more than the threshold amount is first listed under the authority of Section 112(r). If necessary, the risk management plan will be submitted by the appropriate date.

Appendix L

Appendix L

Compliance Report and Plan

Compliance Report and Plan

Appendices I, V, EE, and II contain the compliance status of the facility, and each specific emission unit, for all applicable regulations.

Appendix M

Appendix M

Compliance Statement

Compliance Statement

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

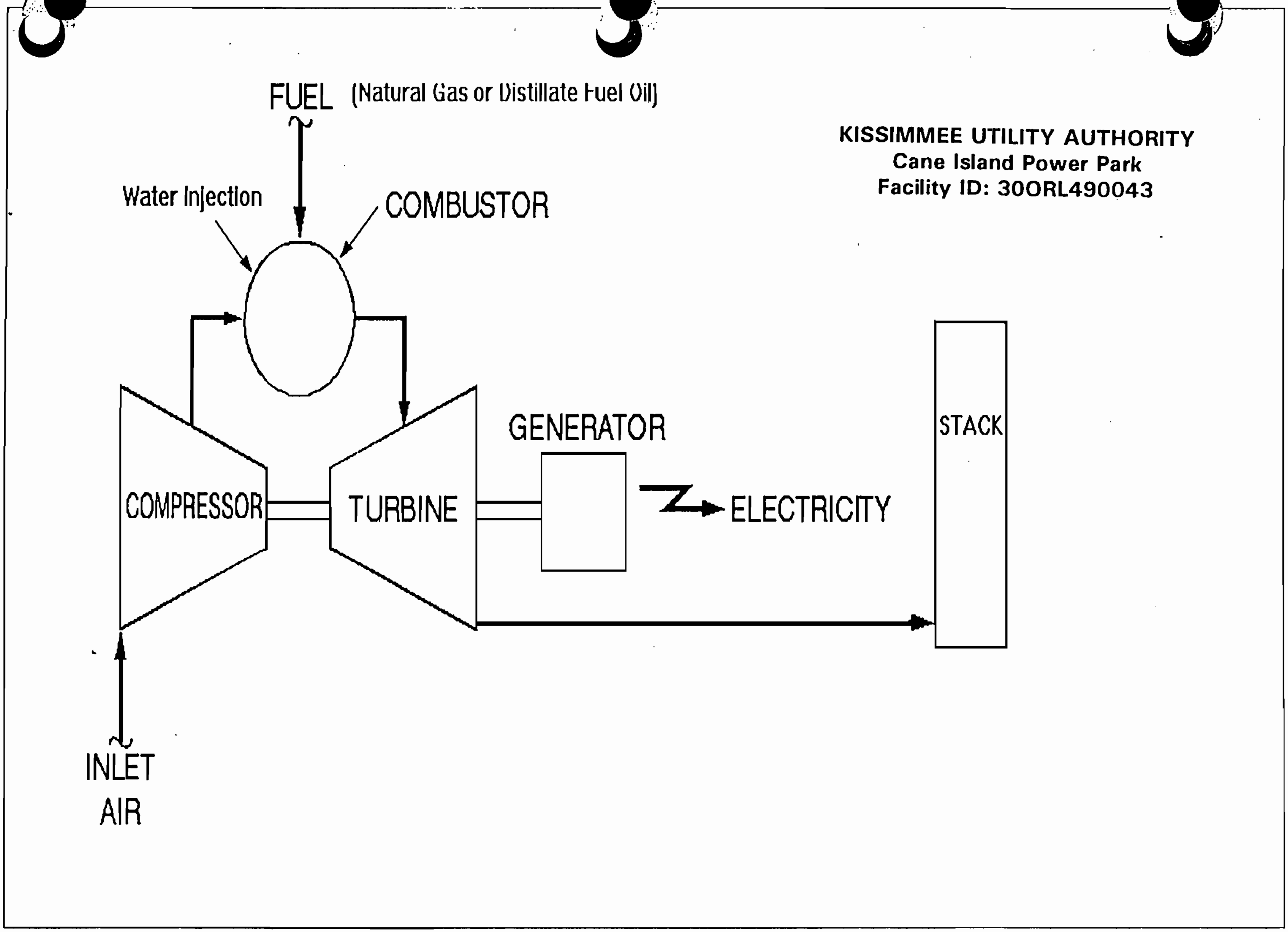
AK Sharma

A. K. Sharma
Responsible Official

Appendix N

Appendix N

Process Flow Diagram



40 MW Simple Cycle Combustion Turbine
Process Flow Diagram
(Ref DEP Form No. 62-210.900(1))

Appendix O

Appendix O

Fuel Analysis or Specification

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3075 CORNERS NORTH COURT
NORCROSS, GEORGIA 30091-5000
(770) 448-5235
(800) 241-6315

KISSIMMEE UTL AUTHORITY - CANE ISLAND	Lab Number : 9568
SCOTT YELVINGTON	Logged Date : 29-MAY-96
P O BOX 423219	Sample Drawn : 28-MAY-96
KISSIMMEE FL 34742-3219	Report Date : 31-MAY-96
	Record Ref.# : 366310

Unit ID : UNIT 2	Mfg. : UNKNOWN
Sample ID : FUEL OIL #2	Model : -
Worksite : CANE ISLAND	PO No.: 10114
Time On Fluid :	Time On System :

TESTING PERFORMED:	MEASURED
Heat of Combustion Calc (fuel oil) D4868	
Ash Content, % wt. - D482	0.001
Sulfur Content by XRF, % wt - D4294	0.03
Water Content KF (ppm) D1744	77
Density,Kg/L @ 15'C - D1298	00.8450
Gross Heat Value, BTU/gl - ASTM D4868	138064
Net Heat Value, BTU/gl - ASTM D4868	129550
Gross Heat Value, BTU/lb - ASTM D4868	19615
Net Heat Value, BTU/lb - ASTM D4868	18405
Arsenic, ppm, EPA 7060	<0000.05
Beryllium, ppm, EPA 7091	<0000.05
Mercury, ppm, EPA 7471	<0000.05
Lead, ppm, EPA 7421	0000.07

RECOMMENDATIONS / COMMENTS:

SAMPLE SUBMITTED AND PROCESSED FOR THE TEST DATA (ONLY).

Respectfully Submitted,

Analysts, Inc.

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NICHOLS LABORATORY, INC.

1924 Tennessee Avenue • Knoxville, Tennessee 37921 • (615) 523-6449

Certificate of Analysis

April 25, 1995

Power Generation Technologies
200 Tech Center Drive
Knoxville, TN 37912

Received: 4/20/95

Purchase Order No: ESC 05093

Lab ID # NF-2893

Sample ID # Kissimmee Utility Authority, Composite Sample
(50 ml each of ten samples)

	T -	60°F	70°F	100°F
1) Specific Gravity @ T ....:		0.8475	0.8455	0.8412
2) Density @ T, g/cc ....:		0.8467	0.8438	0.8412
3) Pounds Per U.S. Gallon @ T ....:		7.0652	7.0408	6.9700
4) Gross Heating Value, Btu/lb ....:		19505		
5) Btu Per Gallon ....:		137,807		

Ref: ASTM D 1250 (tables); D 1298; D 4809-90.

Ultimate Analysis

6) % Carbon ....: 87.16

7) % Hydrogen ....: 12.68

8) % Nitrogen ....:< 0.50

9) % Sulfur ....: 0.0435

10) % Ash ....:< 0.001

11) % Oxygen by Difference ....: 0.00

Ref: ASTM D 129; D 482; D 5291

Sincerely yours,
Nichols Laboratory, Inc.

David V. Deitz
President

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ERIE TESTING LAB
1962 WAGER ROAD
ERIE PA 16509
(814)825-8533

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CERTIFICATE OF ANALYSIS

ENVIRONMENTAL SYSTEMS CORP.
•
200 TECH CENTER DRIVE
ATTN: JAMES M. SUTTON
KNOXVILLE TN 37912

Date Reported 4/27/95
Date Received 4/21/95
Order No 9504-01099
Invoice No 038527
Cust # 005186
Sampled Date 4/12/95
Sampled Time 00:00
Sample Id

Permit No
Cust P.O. #ESC07184

Subject: 11-GAS SAMPLES FOR LHV/DENSITY, RECD. 4/21/95

SMP	TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
1	GAS 01, #1						
	LOWER HEATING VALUE (GAS)	ASTM 1945-80/GPA 2261-90			4/25/95	15:00	EVM
	N[illegible]EN		0.32	%	4/25/95	15:00	EVM
	ME[illegible]E		95.33	%	4/25/95	15:00	EVM
	ETHANE		2.56	%	4/25/95	15:00	EVM
	PROPANE		0.67	%	4/25/95	15:00	EVM
	ISO-BUTANE		0.19	%	4/25/95	15:00	EVM
	N-BUTANE		0.15	%	4/25/95	15:00	EVM
	ISO-PENTANE		0.06	%	4/25/95	15:00	EVM
	N-PENTANE		0.03	%	4/25/95	15:00	EVM
	HEXANES		(0.02	%	4/25/95	15:00	EVM
	CARBON DIOXIDE		0.68	%	4/25/95	15:00	EVM
	BTU, DRY (HIGH HEAT VAL)		1041.89	BTU/CU.FT.	4/25/95	15:00	EVM
	BTU, SAT. (HIGH HEAT VAL)		1023.76	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, DRY (LOW HEAT VAL)		939.43	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, SAT.(LOW HEAT VAL)		923.08	BTU/CU.FT	4/25/95	15:00	EVM
	REAL SPECIFIC GRAVITY		0.5875		4/25/95	15:00	EVM
	ACTUAL NET BTU		939.43	BTU/CU.FT.	4/25/95	15:00	EVM
	ACTUAL NET BTU		20,986.10	BTU/LB.	4/25/95	15:00	EVM
	DENSITY		0.000719717	G/ML	4/25/95	15:00	EVM
	DENSITY		0.04493573	LBS/CU.FT.	4/25/95	15:00	EVM
2	GAS 01, #2						
	LOWER HEATING VALUE (GAS)	ASTM 1945-80/GPA 2261-90			4/25/95	15:00	EVM
	NITROGEN		0.49	%	4/25/95	15:00	EVM
	METHANE		95.24	%	4/25/95	15:00	EVM
	E[illegible]		2.54	%	4/25/95	15:00	EVM

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ENVIRONMENTAL SYSTEMS CORP.
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200 TECH CENTER DRIVE
ATTN: JAMES M. SUTTON
KNOXVILLE TN 37912

Date Reported	4/27/95
Date Received	4/21/95
Order No	9504-01099
Invoice No	038527
Cust #	005186
Sampled Date	4/12/95
Sampled Time	00:00
Sample Id	

Permit No
Cust P.O. #ESC07184

Subject: 11-GAS SAMPLES FOR LHV/DENSITY, RECD. 4/21/95

SMP	TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
2	GAS 01, #2						
	PROPANE		0.65	%	4/25/95	15:00	EVM
	ISO-BUTANE		0.19	%	4/25/95	15:00	EVM
	N-BUTANE		0.14	%	4/25/95	15:00	EVM
	ISO-PENTANE		0.05	%	4/25/95	15:00	EVM
	N-PENTANE		0.03	%	4/25/95	15:00	EVM
	HEXANES		<0.02	%	4/25/95	15:00	EVM
	CARBON DIOXIDE		0.67	%	4/25/95	15:00	EVM
	BTU, DRY (HIGH HEAT VAL)		1039.41	BTU/CU.FT.	4/25/95	15:00	EVM
	BTU, SAT. (HIGH HEAT VAL)		1021.32	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, DRY (LOW HEAT VAL)		937.17	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, SAT.(LOW HEAT VAL)		920.86	BTU/CU.FT	4/25/95	15:00	EVM
	REAL SPECIFIC GRAVITY		0.5874		4/25/95	15:00	EVM
	ACTUAL NET BTU		937.17	BTU/CU.FT.	4/25/95	15:00	EVM
	ACTUAL NET BTU		20,857.83	BTU/LB.	4/25/95	15:00	EVM
	DENSITY		0.000719646	G/ML	4/25/95	15:00	EVM
	DENSITY		0.044931297	LBS/CU.FT.	4/25/95	15:00	EVM
3	GAS 01-02, #3						
	LOWER HEATING VALUE (GAS)	ASTM 1945-80/GPA 2261-90			4/25/95	15:00	EVM
	NITROGEN		0.35	%	4/25/95	15:00	EVM
	METHANE		95.31	%	4/25/95	15:00	EVM
	ETHANE		2.56	%	4/25/95	15:00	EVM
	PROPANE		0.67	%	4/25/95	15:00	EVM
	ISO-BUTANE		0.19	%	4/25/95	15:00	EVM
	N-BUTANE		0.14	%	4/25/95	15:00	EVM
	ISO-PENTANE		0.06	%	4/25/95	15:00	EVM

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Date Reported 4/27/95
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Order No 9504-01099
Invoice No 038527
Cust # 005186
Sampled Date 4/12/95
Sampled Time 00:00
Sample Id

Permit No
Cust P.O. #ESC07184

Subject: 11-GAS SAMPLES FOR LHV/DENSITY, RECD. 4/21/95

SMP	TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
3	GAS 01-02, #3						
	N-PENTANE		0.03	%	4/25/95	15:00	EVM
	[illegible]ES		<0.02	%	4/25/95	15:00	EVM
	CA[illegible]ON DIOXIDE		0.68	%	4/25/95	15:00	EVM
	BTU, DRY (HIGH HEAT VAL)		1041.58	BTU/CU.FT.	4/25/95	15:00	EVM
	BTU, SAT. (HIGH HEAT VAL)		1023.46	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, DRY (LOW HEAT VAL)		939.15	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, SAT.(LOW HEAT VAL)		922.81	BTU/CU.FT	4/25/95	15:00	EVM
	REAL SPECIFIC GRAVITY		0.5876		4/25/95	15:00	EVM
	ACTUAL NET BTU		939.15	BTU/CU.FT.	4/25/95	15:00	EVM
	ACTUAL NET BTU		20,897.20	BTU/LB.	4/25/95	15:00	EVM
	DENSITY		0.000719807	G/ML	4/25/95	15:00	EVM
	DENSITY		0.044941301	LBS/CU.FT.	4/25/95	15:00	EVM
4	GAS 02, #4						
	LOWER HEATING VALUE (GAS)	ASTM 1945-80/GPA 2261-90			4/25/95	15:00	EVM
	NITROGEN		0.36	%	4/25/95	15:00	EVM
	METHANE		95.36	%	4/25/95	15:00	EVM
	ETHANE		2.55	%	4/25/95	15:00	EVM
	PROPANE		0.65	%	4/25/95	15:00	EVM
	ISO-BUTANE		0.19	%	4/25/95	15:00	EVM
	N-BUTANE		0.14	%	4/25/95	15:00	EVM
	ISO-PENTANE		0.05	%	4/25/95	15:00	EVM
	N-PENTANE		0.03	%	4/25/95	15:00	EVM
	HEXANES		<0.02	%	4/25/95	15:00	EVM
	CARBON DIOXIDE		0.67	%	4/25/95	15:00	EVM
	[illegible] DRY (HIGH HEAT VAL)		1040.72	BTU/CU.FT.	4/25/95	15:00	EVM

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ATTN: JAMES M. SUTTON
KNOXVILLE TN 37912

Date Reported 4/27/95
Date Received 4/21/95
Order No 9504-01099
Invoice No 038527
Cust # 005186
Sampled Date 4/12/95
Sampled Time 00:00
Sample Id

Permit No
Cust P.O. #ESC07184

Subject: 11-GAS SAMPLES FOR LHV/DENSITY, RECD. 4/21/95

SMP	TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
4	GAS 02, #4						
	BTU, SAT. (HIGH HEAT VAL)		1022.61	BTU/CU.FT.	4/25/95	15:00	EVM
	NET [illegible] DRY (LOW HEAT VAL)		938.35	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, SAT. (LOW HEAT VAL)		922.02	BTU/CU.FT	4/25/95	15:00	EVM
	REAL SPECIFIC GRAVITY		0.5869		4/25/95	15:00	EVM
	ACTUAL NET BTU		938.35	BTU/CU.FT.	4/25/95	15:00	EVM
	ACTUAL NET BTU		20,981.34	BTU/LB.	4/25/95	15:00	EVM
	DENSITY		0.000719852	G/ML	4/25/95	15:00	EVM
	DENSITY		0.044894187	LBS/CU.FT.	4/25/95	15:00	EVM
5	GAS 02, #5						
	LOWER HEATING VALUE (GAS)	ASTM 1945-80/GPA 2261-90			4/25/95	15:00	EVM
	NITROGEN		0.53	%	4/25/95	15:00	EVM
	METHANE		95.21	%	4/25/95	15:00	EVM
	ETHANE		2.54	%	4/25/95	15:00	EVM
	PROPANE		0.65	%	4/25/95	15:00	EVM
	ISO-BUTANE		0.19	%	4/25/95	15:00	EVM
	N-BUTANE		0.14	%	4/25/95	15:00	EVM
	ISO-PENTANE		0.05	%	4/25/95	15:00	EVM
	N-PENTANE		0.03	%	4/25/95	15:00	EVM
	HEXANES		<0.02	%	4/25/95	15:00	EVM
	CARBON DIOXIDE		0.67	%	4/25/95	15:00	EVM
	BTU, DRY (HIGH HEAT VAL)		1038.90	BTU/CU.FT.	4/25/95	15:00	EVM
	BTU, SAT. (HIGH HEAT VAL)		1020.83	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, DRY (LOW HEAT VAL)		936.71	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, SAT. (LOW HEAT VAL)		920.41	BTU/CU.FT	4/25/95	15:00	EVM
	R[illegible]ECIFIC GRAVITY		0.5875		4/25/95	15:00	EVM

Certificate Of Analysis Continued On Next Page

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ERIE TESTING LAB
1962 WAGER ROAD
ERIE PA 16509
(814) 825-8533

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CERTIFICATE OF ANALYSIS

ENVIRONMENTAL SYSTEMS CORP.
.
200 TECH CENTER DRIVE
ATTN: JAMES M. SUTTON
KNOXVILLE TN 37912

Date Reported 4/27/95
Date Received 4/21/95
Order No 9504-01099
Invoice No 038527
Cust # 005186
Sampled Date 4/12/95
Sampled Time 00:00
Sample Id

Permit No
Cust P.O. #ESC07184

Subject: 11-GAS SAMPLES FOR LHV/DENSITY, RECD. 4/21/95

SMP	TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
5	GAS 02, #5						
	ACTUAL NET BTU		936.71	BTU/CU.FT.	4/25/95	15:00	EVM
	ACT[illegible]ET BTU		20,844.55	BTU/LB.	4/25/95	15:00	EVM
	DE[illegible]		0.000719751	G/ML	4/25/95	15:00	EVM
	DENSITY		0.044937841	LBS/CU.FT.	4/25/95	15:00	EVM
7	GAS 03, #7						
	LOWER HEATING VALUE (GAS)	ASTM 1945-80/GPA 2261-90			4/25/95	15:00	EVM
	NITROGEN		0.50	%	4/25/95	15:00	EVM
	METHANE		95.35	%	4/25/95	15:00	EVM
	ETHANE		2.49	%	4/25/95	15:00	EVM
	PROPANE		0.65	%	4/25/95	15:00	EVM
	ISO-BUTANE		0.20	%	4/25/95	15:00	EVM
	N-BUTANE		0.15	%	4/25/95	15:00	EVM
	ISO-PENTANE		0.06	%	4/25/95	15:00	EVM
	N-PENTANE		0.03	%	4/25/95	15:00	EVM
	HEXANES		<0.02	%	4/25/95	15:00	EVM
	CARBON DIOXIDE		0.57	%	4/25/95	15:00	EVM
	BTU, DRY (HIGH HEAT VAL)		1040.62	BTU/CU.FT.	4/25/95	15:00	EVM
	BTU, SAT. (HIGH HEAT VAL)		1022.52	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, DRY (LOW HEAT VAL)		938.27	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, SAT.(LOW HEAT VAL)		921.94	BTU/CU.FT	4/25/95	15:00	EVM
	REAL SPECIFIC GRAVITY		0.5867		4/25/95	15:00	EVM
	ACTUAL NET BTU		938.27	BTU/CU.FT.	4/25/95	15:00	EVM
	ACTUAL NET BTU		20,908.20	BTU/LB.	4/25/95	15:00	EVM
	DENSITY		0.000718756	G/ML	4/25/95	15:00	EVM
	DE[illegible]		0.044875676	LBS/CU.FT.	4/25/95	15:00	EVM

Certificate Of Analysis Continued On Next Page

MAY 19 '95 15:15 615068708977-0 000

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Microbac Laboratories, Inc.

ERIE TESTING LAB
1962 WAGER ROAD
ERIE PA 16503
(814)825-8533

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CERTIFICATE OF ANALYSIS

Attn: James Sutton

ENVIRONMENTAL SYSTEMS CORP.

200 TECH CENTER DRIVE

KNOXVILLE TN 37912

Date Reported	5/15/95
Date Received	5/11/95
Order No	9505-00639
Invoice No	039261
Cust #	005186
Sampled Date	0/00/00
Sampled Time	00:00
Sample Id	

Permit No
Cust P.O.

Subject: GAS SAMPLES (MILFORD PLANT, KISSIMMEE UTILITY), RECD.5/11

SMP	TEST	METHOD	RESULT	UNITS	DATE	TIME	TECH
1	MILFORD PLANT, 5/5/95 @ 07:00						
	LOWER HEATING VALUE (GAS)	ASTM 1945-88/GPA 2261-90			5/12/95	10:00	EVM
	NITROGEN		1.02	%	5/12/95	10:00	EVM
	METHANE		95.82	%	5/12/95	10:00	EVM
	ETH[illegible]		2.16	%	5/12/95	10:00	EVM
	PRO[illegible]		0.28	%	5/12/95	10:00	EVM
	ISO-BUTANE		0.08	%	5/12/95	10:00	EVM
	N-BUTANE		0.04	%	5/12/95	10:00	EVM
	ISO-PENTANE		0.02	%	5/12/95	10:00	EVM
	N-PENTANE		0.02	%	5/12/95	10:00	EVM
	HEXANES		<0.02	%	5/12/95	10:00	EVM
	CARBON DIOXIDE		0.51	%	5/12/95	10:00	EVM
	BTU, DRY (HIGH HEAT VAL)		1021.15	BTU/CU.FT.	5/12/95	10:00	EVM
	BTU, SAT. (HIGH HEAT VAL)		1003.39	BTU/CU.FT.	5/12/95	10:00	EVM
	NET BTU, DRY (LOW HEAT VAL)		920.86	BTU/CU.FT.	5/12/95	10:00	EVM
	NET BTU, SAT. (LOW HEAT VAL)		904.24	BTU/CU.FT	5/12/95	10:00	EVM
	REAL SPECIFIC GRAVITY		0.5787		5/12/95	10:00	EVM
	ACTUAL NET BTU		920.85	BTU/CU.FT.	5/12/95	10:00	EVM
	ACTUAL NET BTU		20,785.88	BTU/LB.	5/12/95	10:00	EVM
	DENSITY		0.000784968	G/ML	5/12/95	10:00	EVM
	DENSITY		0.044264565	LBS/CU.FT.	5/12/95	10:00	EVM
2	KISSIMMEE UTILITY, CANE ISLAND GAS REG. STATION, 5/9/95 @ 13:15 BY J. LOONEY						
	SULFUR, TOTAL (NATURAL GAS)	ASTM D1072-80			5/11/95	15:00	EVM
	TOTAL SULFUR		<1.0	GR/100CF	5/11/95	15:00	EVM
	TOTAL SULFUR (% BY WEIGHT)		<0.0031	%	5/11/95	15:00	EVM

Certificate Of Analysis Continued On Next Page

<0.0031%

Appendix P

Appendix P

Detailed Description of Control Equipment

Detailed Description of Control Equipment

1) Water Injection: A control technology used to limit NOx emissions. The thermal NOx contribution to total NOx emission is reduced by lowering the combustion temperature through the use of water injection in the combustion zones of the combustion turbine. Water injection will be used for both natural gas and oil firing.

2) Use of low sulfur fuel oil (0.05 percent) and the use of natural gas.

Appendix Q

Appendix Q

Description of Stack Sampling Facilities

(Excerpt from unit 1 stack testing report)

2.0 Technical Approach

2.1 Particulate Sampling

2.1.1 Location of Traverse Points

To insure representative sampling of the stack the cross section was divided into discreet sampling points according to the procedures described in 40 CFR 60; Appendix A, Method 1, Sample and Velocity Traverses for Stationary Sources. The sampling points were located on two perpendicular diameters of the stack, and each diameter was divided into twelve sampling points. During the one hour compliance test runs for PM, the stack gas characteristics (i.e., flow, temp.) were audited every 5 minutes. Figure 1 shows the layout of the stack and the locations of the sampling points.

2.1.2 Velocity and Volumetric Flow Measurements

Velocity measurements were performed for the PM isokinetic sampling train using the procedures outlined in 40 CFR, Part 60, Appendix A, Method 2, Determination of Stack Gas Velocity and Volumetric Flow Rate, during each compliance test run. The velocity pressures were measured using an "S"-type pitot tube and a standard oil filled manometer. The calibration procedures for the pitot tubes are included in Appendix C.

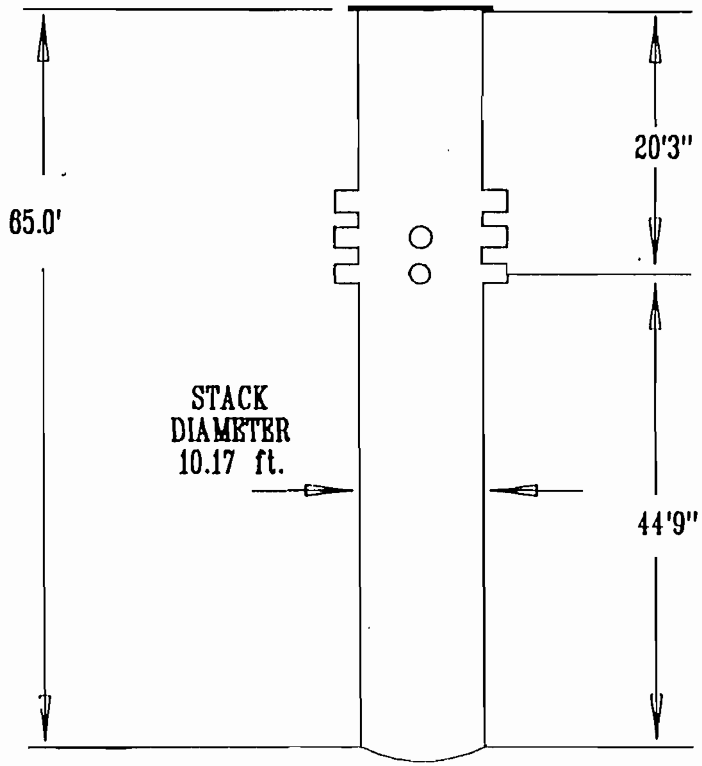
2.1.3 Temperature Measurements

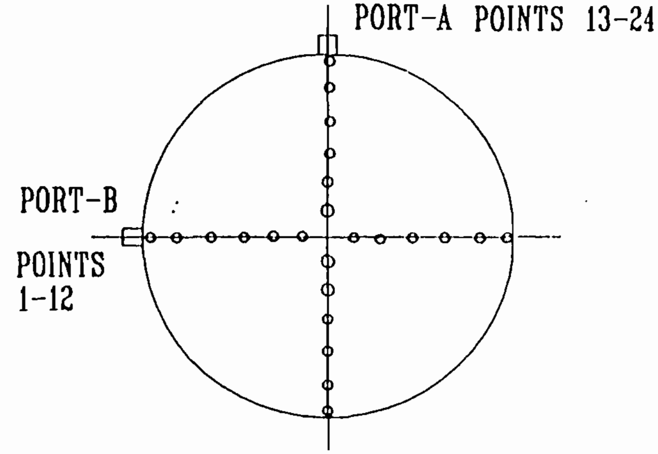
The temperature of the stack gas was measured using K-type thermocouples and dedicated digital temperature readouts. The isokinetic sampling train was equipped with a thermocouple. The temperature was recorded on the sampling data sheet at each traverse point location. The stack temperatures were arithmetically averaged and used to calculate the volumetric flow rates at standard and dry standard conditions. Detailed accuracy and calibration information is described in Section 4.2.2. Calibration data sheets are included in Appendix C.

2.1.4 Carbon Dioxide and Oxygen

The CO_2 and O_2 stack gas concentrations were determined according to procedures specified in CFR 40, Part 60, Appendix A, Method 3A, Determination of Oxygen and Carbon Dioxide Concentrations in Emissions From Stationary Sources (Instrumental Analyzer Procedure). Figure 3 is a schematic of the CEM sampling system. Access to the stack was through a sample line installed approximately 65 feet above grade. A stainless steel probe was used to extract the gas sample from the stack. A 1/4 inch heated Teflon® line transported the sample

STARTING DATE:	DATE LAST REV.: 12/20/94	DRA[illegible]CK.BY: R.MOORE	INITIATOR: J. KELLEY	DWG. NO.:
DRAWN BY: M. MOWERY	DRAWN BY: T. GREGG	ENG. CHCK. BY: R. MOORE	PROJ. MGR.: J. KELLEY	PROJ. NO.: 410226





CROSS SECTION

FIGURE 1

SCHEMATIC OF STACK & SAMPLING PORTS
KISSIMEE UTILITY AUTHORITY
IT PROJECT NO. 410226

IT INTERNATIONAL TECHNOLOGY CORPORATION

from the point of extraction to the gas conditioning system and analyzer. The moisture was removed from the gas stream by the gas conditioning system. The analyzer was located in a temperature controlled area to minimize thermal affects on the calibration of the instrument. The O_2 analyzer used was manufactured by Teledyne, model number 90. The CO_2 analyzer used was manufactured by Horiba, model number PIR 2000. The O_2 and CO_2 analyzer was operated continuously over the entire test period during which the readings of the analyzer were recorded by a computerized data logger which recorded the concentrations on a one minute average. Quality control procedures implemented during the testing included multi-point calibrations, calibration drift tests, bias tests, and response time tests for the both analyzers. The analyzers were calibrated daily before and after each test run with Protocol 1 gases. The O_2 analyzer was calibrated using the following concentrations of O_2 gas: 10 % and 15.96 %. The CO_2 analyzer was calibrated using the following concentrations of CO_2 gas: 2.99 % and 9.95 %. The calibration gas certification sheets can be found in Appendix B.

2.1.5 Moisture Determinations

The moisture content of the stack gas was determined using procedures outlined in 40 CFR 60; Appendix A, Reference Method 4, Determination of Moisture in Stack Gases. The Method 4 sampling was incorporated into the PM isokinetic sampling train for all six compliance test runs.

The moisture was determined for each sampling run by gravimetrically measuring the weight gain of the chilled impingers over the length of the sampling runs. This weight gain was used in calculations in conjunction with the corrected sample volume to determine the moisture percentage in the stack gas.

2.1.6 Particulate Sampling Procedure

The particulate sampling was performed using the sampling procedures described in 40 CFR, Part 60; Appendix A, Reference Method 5, Determination of Particulate Emissions From Stationary Sources. To measure particulate emission rates and concentrations, a slip stream was withdrawn isokinetically from the source and collected on a heated filter and drawn through a series of chilled impingers. A schematic of the sampling train is shown in Figure 2.

The general sampling procedures were performed in accordance with EPA Reference Method 5. The equipment used to perform the sampling was produced by Anderson Samplers, Inc.

ARTING DATE: 7/14/93	DATE LAST REV.: 12/21/94	DRAFT.C BY: R. MOORE	INITIATOR: J.KELLEY	DWG. NO.:
DRAWN BY: M. MOWERY	DRAWN BY: T.GREGG	ENG. CHCK. BY: D. KING	PROJ. MGR.: J.KELLEY	PROJ. NO.: 410226

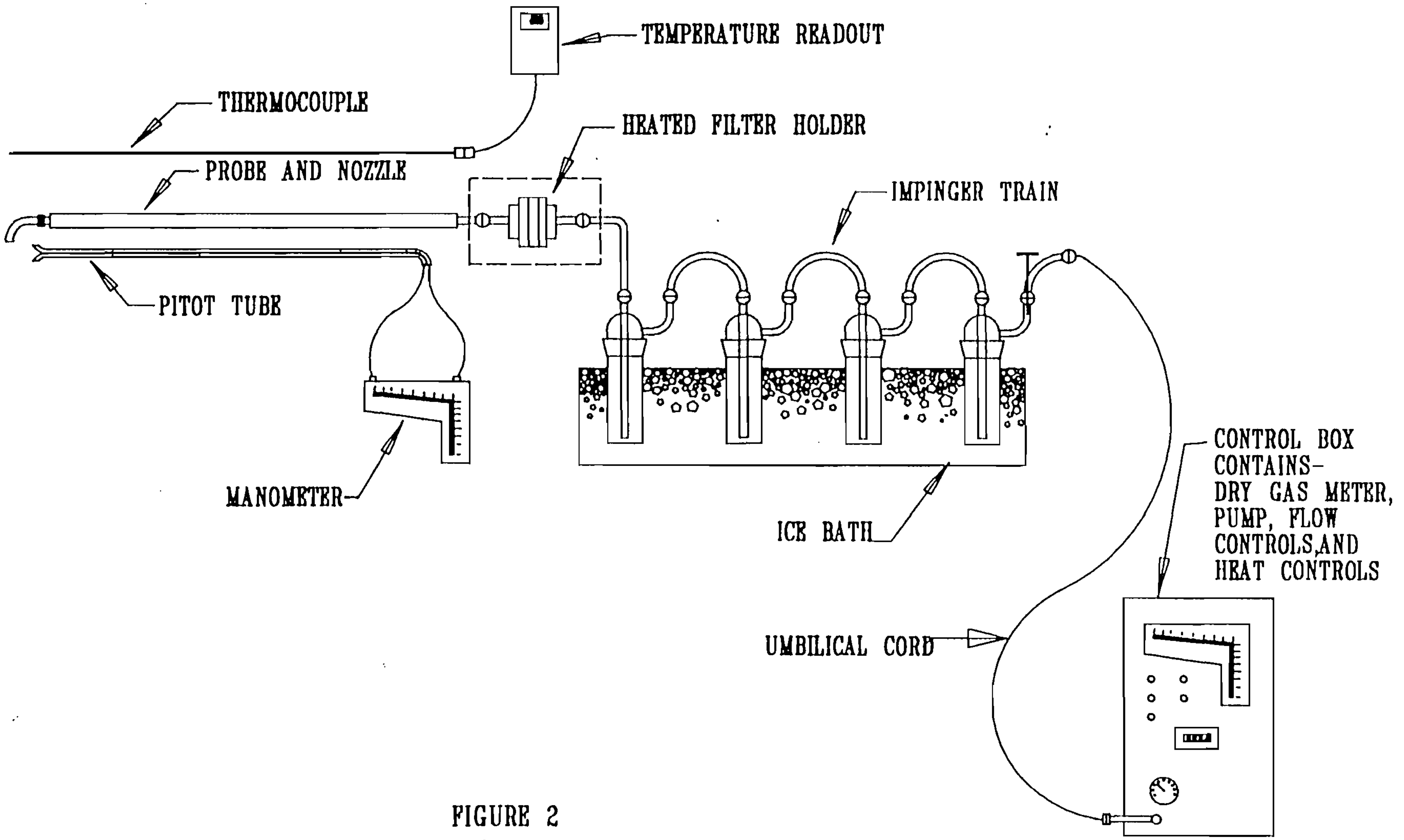


FIGURE 2

SCHEMATIC OF METHOD 5 PARTICULATE TRAIN
KISSIMEE UTILITY AUTHORITY
IT PROJECT NO. 410226

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and NuTech Corporation. The equipment has the approval of and meets the standards of calibration accuracy as set forth by EPA.

The sampling equipment consists of three main units: the pump, control units and sampling train. The pump is a Gast® lubricated fiber vane rotary pump altered for leak-free operation. The pump is connected to the control unit, which contains a Rockwell dry gas meter, dual manometers, and a calibrated orifice system designed to enable isokinetic sampling. The sampling train is connected to the control unit by means of a flexible umbilical cord, and contains the impinger case, filter oven, stainless steel sampling nozzle and glass probe.

The probe used was constructed of glass wrapped with a heating element and incased in a 304 stainless steel tube. The heating element maintains probe temperatures above the gaseous dew point of the stack gas and prevents condensation of moisture or acid gases in the probe. The probe was rigidly mounted to the sampling oven and was directly connected to a heated glass fiber filter. The filter was placed on a glass frit and housed in a glass filter bell and teflon support housing. The filter oven temperature was maintained between 225 and 275 °F throughout the sampling runs.

Four ball-topped impingers in an ice bath were connected to the back of the filter. The first impinger was initially empty and was used as a moisture trap. The second and third impingers each contained a 100 ml solution of water. The fourth impinger contained indicating silica gel, weighed to the nearest 0.1 gram. The impinger section of the train was assembled in a dedicated clean area prior to being taken to the stack where the probe and filter were attached to the train. All fittings in the system were rigid ground glass to glass to prevent leakage.

The stack sample was drawn isokinetically through a glass nozzle, the heated probe and into the heated filter assembly, where the particulate matter was collected on a preweighed filter. The filtered gas then passed through the impinger system which condensed moisture and collected any vapor phase materials which may have passed through the filter. The dry, cooled gas stream then passed through the umbilical cord to the dry gas meter, orifice and pump.

The velocity and stack temperature were monitored at each sampling point to insure that isokinetic sampling rates were maintained. Leak checks were performed prior to sampling, and again immediately after removing the probe from the stack, before the sampling train was moved to the other sampling port. All leak checks were performed as specified in Method 5. After the sampling train was positioned at the second sampling port, it was leak checked again to ensure no leak had developed during the transfer of the train from one port to the other. At the conclusion of the sampling run the train then had to pass a final leak check before sample recovery procedures were initiated.

2.2 Nitrogen Oxides (NOx) Continous Emission Monitoring

The stack gases from Gas Turbine Unit #1 were sampled for nitrogen oxides (NO_x) concentration using a Thermo Electron Model 10A Chemilüminescent NO-NO_x Gas Analyzer. Figure 3 shows a schematic of the CEM sampling system. The key components of this analyzer include the reaction chamber, the photomultiplier tube, and the ozonator. The cylindrical reaction chamber is where sample gas containing NO molecules mixes with O_3 molecules from the ozonator. Electronically excited NO_2 molecules are created which emit light (chemiluminescence) as the orbital electrons decay to their ground states. The chemiluminescence is monitored through an optical filter by a high-sensitivity photomultiplier tube positioned at one end of the reactor. The filter-photomultiplier combination responds to light in a narrow wavelength band unique to the desired electron decay. Sample flow is controlled so that the output from the photomultiplier tube is linearly proportional to the NO concentration. The basic chemiluminescent analyzer is only sensitive to NO molecules. To measure NO_x (i.e., NO_2 plus NO) the NO_2 must first be converted to NO. The conversion is accomplished by passing the sample gas through a temperature controlled chamber which disassociates NO_2 to NO plus oxygen.

NO_x sampling was performed in accordance with the procedures presented in EPA Method 20. Access to the stack was through a heated sample line installed approximately 65 feet above grade. A stainless steel probe was used to extract the gas sample from the stack. A 1/4 inch heated Teflon® line transported the sample from the point of extraction to the gas conditioning system and analyzer. The moisture was removed from the gas stream by the gas conditioning system. The analyzer was located in a temperature controlled area to minimize thermal affects on the calibration of the instrument. The NO_x monitor was operated continuously over the entire test period during which the readings of the analyzer were recorded by a computerized data logger which recorded concentrations on a one minute average.

STARTING DATE: 7/29/93	DATE LAST REV.: 12/21/94	DRAFT. CHCK. BY: R. MOORE	INITIATOR: J.KELLEY	DWG. NO.:
DRAWN BY: R. BRYSON	DRAWN BY: T.GREGG	ENG. CHCK. BY: R. MOORE	PROJ. MGR.: J.KELLEY	PROJ. NO.: 410226

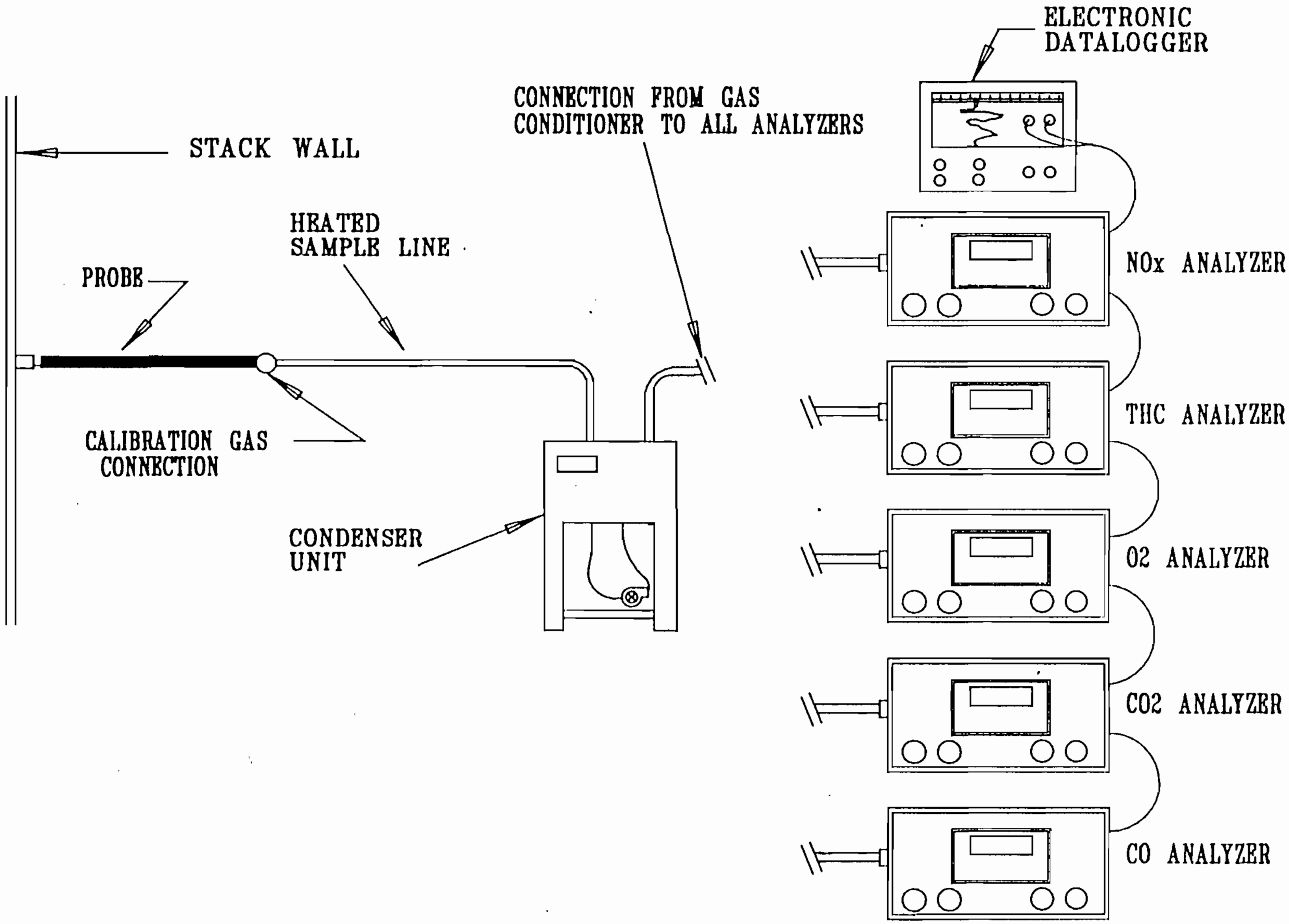

FIGURE 3

SCHEMATIC OF TYPICAL CONTINUOUS EMISSION MONITOR
KISSIMEE UTILITY AUTHORITY
IT PROJECT NO. 410226

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Quality control procedures implemented during the testing included multi-point calibrations, calibration drift tests, bias tests, and response time tests for the NO_x monitor. The NO_x monitor was calibrated daily before and after each test run. These calibrations consisted of introducing prepurified nitrogen as a zero gas and three known concentrations of Protocol 1 NO_x. The specific calibration gas concentrations were 25.85 ppm, 46.12 ppm, and 85.8 ppm. The Protocol 1 calibration gas certification sheets can be found in Appendix B.

Bias checks were also performed in conjunction with the monitor calibrations. These checks were performed by introducing calibration gas at the point of sample extraction on the stack. This allowed calibration gases to travel through the complete NO_x monitoring system.

Response time tests were performed prior to any sampling being performed. Alternating the introduction of span and zero calibration gas during the bias checks three times and recording the time required for the monitor to reach 95 percent of the final stable value enabled the determination of mean upscale and downscale response times.

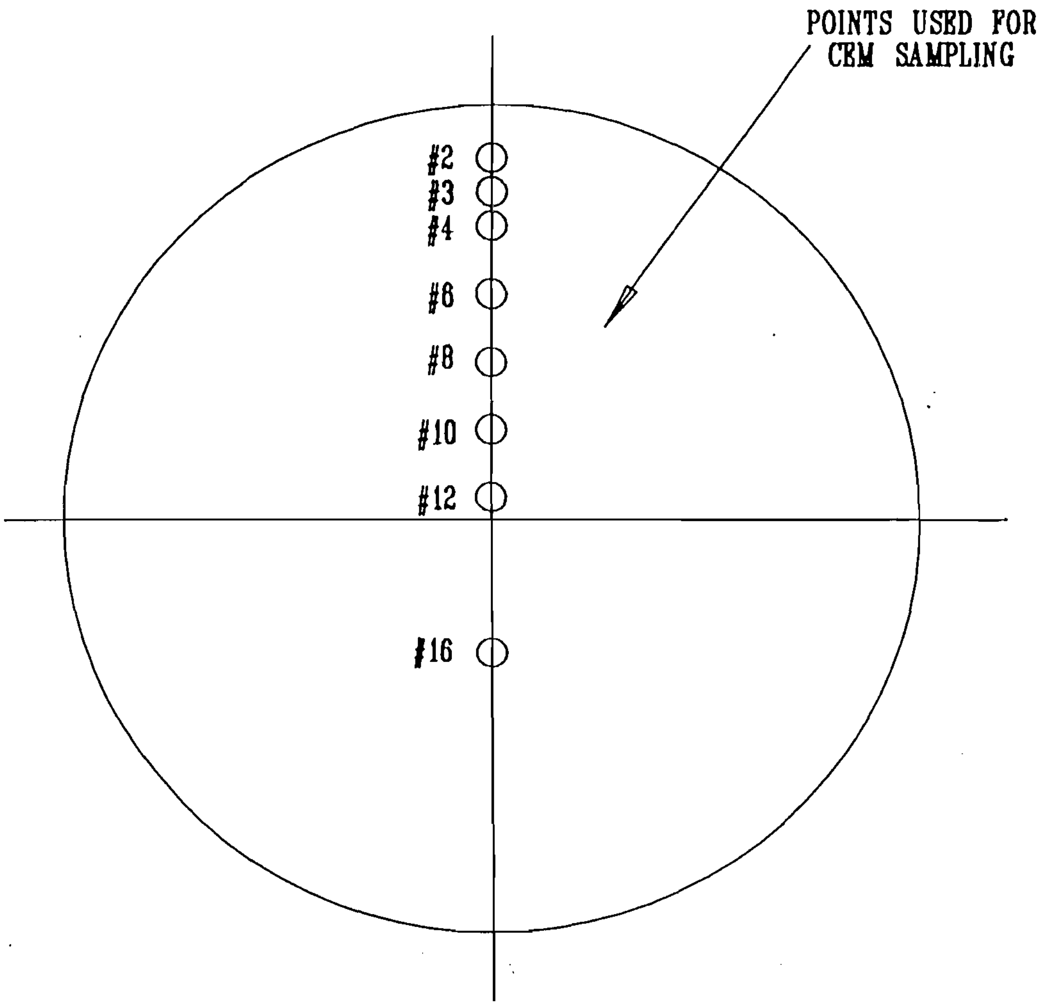
Zero and calibration drift were also determined for each run of the testing. This was accomplished by comparing zero and upscale calibrations from before and after each test run.

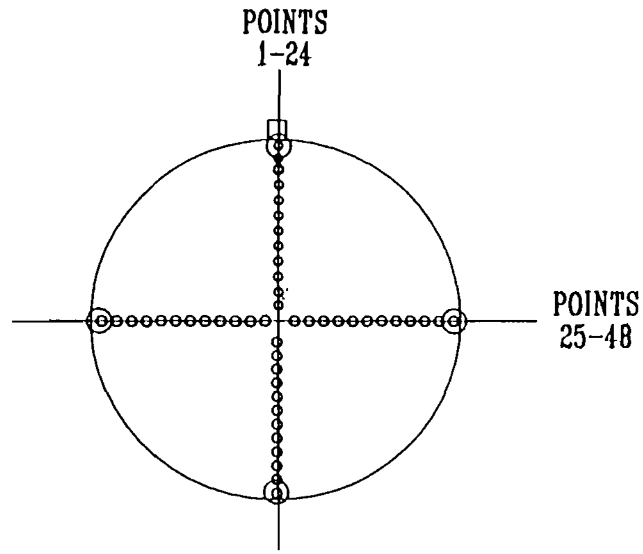
Calibration of the NOx analyzer was performed using three up scale span gases and a zero gas. Calibration of the NOx analyzer was performed before and after each test run.

Before and after each test run, system bias checks were performed by introducing calibration gases at the point where stack gases were being extracted from the source. This enabled the evaluation of the affects of the sampling system (Teflon® line and gas conditioning system) on the response of the analyzer. Instrument calibrations were compared before and after each test run to determine the calibration and zero drift.

A preliminary O_2 traverse was conducted for the purpose of selecting sampling points of low O_2 and high CO_2 concentrations. The traverse for primary diluent sampling was conducted at 30% of full load. The number of sample points used was 48 as shown in Figure 4. The minimum sampling time at each point was 94 seconds (60 seconds + 34 second response time). The diluent sampling results for the 48 traverse points are summarized in Figure 5. The eight sampling points that were chosen for sampling based on diluent conditions are also depicted in Figure 4. Each of the eight points was sampled for 7.5 minutes during each of

STARTING DATE:	DATE LAST REV.: 12/21/94	DRAFT[illegible] BY: R. MOORE	INITIATOR: J. KELLEY	DWG. NO.:
DRAWN BY: M. MOWERY	DRAWN BY: T. GREGG	ENG. CHCK. BY: R. MOORE	PROJ. MGR.: J. KELLEY	PROJ. NO.: 410226





CROSS SECTION

DISTANCE INSIDE STACK

POINT #

#2 = 15.4"
#3 = 18.2"
#4 = 21.1"
#6 = 27.6"
#8 = 35.2"
#10 = 44.7"
#12 = 60.1"
#16 = 105.4"

FIGURE 4

SCHEMATIC OF STACK & SAMPLING PORTS FOR CEMS
KISSIMEE UTILITY AUTHORITY
IT PROJECT NO. 410226

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Preliminary Diluent Traverse Data
Figure #5

PROJECT NAME:	Kissimee Utility Authority
PROJECT NUMBER:	410226
LOCATION:	Kissimee,Fla.
DATE:	11-07-94

Sample Point	Diluent Concentration,%	
	O2	CO2
1	15.85 %	2.4 %
2	15.74 %	2.5 %
3	15.74 %	2.5 %
4	15.74 %	2.5 %
5	15.84 %	2.3 %
6	15.75 %	2.5 %
7	15.80 %	2.3 %
8	15.75 %	2.5 %
9	15.77 %	2.4 %
10	15.76 %	2.5 %
11	15.80 %	2.4 %
12	15.74 %	2.5 %
13	15.82 %	2.4 %
14	15.82 %	2.4 %
15	15.78 %	2.3 %
16	15.75 %	2.5 %
17	15.81 %	2.3 %
18	15.82 %	2.3 %
19	15.85 %	2.4 %
20	15.79 %	2.3 %
21	15.85 %	2.4 %
22	15.84 %	2.4 %
23	15.79 %	2.3 %
24	15.86 %	2.5 %
25	15.81 %	2.5 %
26	15.82 %	2.4 %
27	15.85 %	2.5 %
28	15.79 %	2.3 %
29	15.85 %	2.5 %
30	15.84 %	2.4 %
31	15.79 %	2.4 %
32	15.86 %	2.3 %
33	15.79 %	2.5 %
34	15.85 %	2.5 %
35	15.84 %	2.4 %
36	15.79 %	2.5 %
37	15.86 %	2.3 %
38	15.81 %	2.5 %
39	15.82 %	2.3 %
40	15.85 %	2.5 %
41	15.79 %	2.4 %
42	15.86 %	2.4 %
43	15.81 %	2.3 %
44	15.82 %	2.5 %
45	15.85 %	2.5 %
46	15.79 %	2.4 %
47	15.85 %	2.5 %
48	15.84 %	2.3 %

the 1 hour compliance test runs and for at least 2.5 minutes during each of the Subpart GG test runs.

2.3 Total Hydrocarbon Sampling Procedures

Sampling for total hydrocarbons (THC) was performed according to the method described in the U.S. EPA Code of Federal Regulations, Reference Method 25A, Determination of Total Gaseous Organic Concentration using a Flame Ionization Analyzer. Figure 3 is a schematic of the CEM sampling system. Access to the stack was through a heated sample line installed approximately 65 feet above grade. A stainless steel probe was used to extract the gas sample from the stack. A 1/4 inch heated Teflon® line transported the sample from the point of extraction to the gas conditioning system and analyzer. The moisture was removed from the gas stream by the gas conditioning system. The analyzer was located in a temperature controlled area to minimize thermal affects on the calibration of the instrument. The THC analyzer used was manufactured by J.U.M. Engineering, model number VE-7. The THC monitor was operated continuously over the entire test period during which the readings of the analyzer were recorded by a computerized data logger which recorded the concentrations on a one minute average. Quality control procedures implemented during the testing included multi-point calibrations, calibration drift tests, bias tests, and response time tests for the THC analyzer. The THC monitor was calibrated daily before and after each test run with Protocol 1 gases. The THC analyzer was calibrated using the following concentrations of propane gas: 24.8 ppm, 55.43 ppm, and 84.81 ppm. The Protocol 1 calibration gas certification sheets can be found in Appendix B.

2.4 Carbon Monoxide Sampling Procedures

Sampling for carbon monoxide (CO) was performed according to the method described in the U.S. EPA Code of Federal Regulations, Reference Method 10, Determination of Carbon Monoxide Emissions from Stationary Sources. Figure 3 is a schematic of the CO CEM sampling system. Access to the stack was through a heated sample line installed approximately 65 feet above grade. A stainless steel probe was used to extract the gas sample from the stack. A 1/4 inch heated Teflon® line transported the sample from the point of extraction to the gas conditioning system and analyzer. The moisture was removed from the gas stream by the gas conditioning system. The analyzer was located in a temperature controlled area to minimize thermal affects on the calibration of the instrument. The CO analyzer used was manufactured by TECO, model number 48. The CO analyzer was operated continuously over the entire test period during which the readings of the analyzer were recorded by a computerized data logger which recorded the concentrations on a one minute average. Quality control procedures implemented during the testing included multi-point calibrations, calibration drift tests, bias tests, and response time tests for the CO analyzer. The CO analyzer was calibrated daily before and after each test run with Protocol 1 gases. The CO analyzer was calibrated using the following concentrations of carbon monoxide gas: 47.01 ppm and 85.05 ppm. The Protocol 1 calibration gas certification sheets can be found in Appendix B.

2.5 Visible Emission Testing Procedures

Sampling for carbon monoxide (CO) was performed according to the method described in the U.S. EPA Code of Federal Regulations, Reference Method 9, Visual Determination of the Opacity of Emissions from Stationary Sources. A one hour visible emission (VE) test was conducted for each PM test run while the unit was operating at full load. The VE testing was conducted simultaneously with the NO_x, CO, PM and THC sampling.

2.6 SO_2, As, Be, Pb Fuel Sampling Procedures

Sulfur Dioxide emissions have been calculated using the fuel analysis data included in Appendix B. Analytical method ASTM D4294 was used to determine the sulfur content of the #2 distillate fuel, while ASTM D3246-81 was used to determine the sulfur content of the natural gas. Analytical method ASTM D 5056 was used to determine the concentration of arsenic, beryllium, mercury, and lead in the #2 distillate fuel.

Appendix R

Appendix R

Compliance Test Report

Compliance Test Report

The air construction permit (AC49-205703) contains several specific conditions relating to the performance of emissions compliance testing at the KUA Cane Island Power Park. The conditions relate to notification and reporting procedures and emission compliance test methods. The specific conditions relating to compliance testing listed in the aforementioned permit are provided below. A table showing the dates when each of these requirements were completed is provided following the conditions.

Notification/Reporting Requirements

Specific Condition 8: Compliance with the NOx, SO2, CO, PM, PM10, and VOC standards shall be determined (while operating at 95-100% of the permitted maximum heat rate input corresponding to the particular ambient conditions) within 180 days of initial operation of the maximum capability of the unit and annually thereafter, by the following reference methods as described in 40 CFR 60, Appendix A (July 1991 version) and adopted by reference in F.A.C. Rule 17-2.700.

Method 1	Sample and Velocity Traverse
Method 2	Volumetric Flow Rate
Method 3	Gas Analysis
Method 5/17	Determination of Particulate Emissions from Stationary Sources
Method 9	Visual Determination of the Opacity of EMissions from Stationary Sources
Method 8	Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources (for fuel oil firing only)
Method 10	Determination of Carbon Monoxide Emissions from Stationary Sources
Method 20	Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbine
Method 25A	Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer

Other DEP approved methods may be used for compliance testing after prior Departmental approval.

Specific Condition 9: Method 5 or 17 must be performed on each unit to determine the initial compliance status of particulate matter emissions of the unit. Thereafter, the opacity emissions test may be used unless 10 percent opacity is exceeded.

Specific Condition 10: Compliance with the SO2 emission limit can also be determined by calculations based on fuel analysis using ASTM D4294 for the sulfur content of the liquid fuels and ASTM D3246-81 for sulfur content of gaseous fuels.

Specific Condition 11: Trace elements of Beryllium (Be) shall be tested during initial compliance test using EMTIC Interim Test Method. As an alternative, Method 104 may be used; or Be may be determined from fuel sample analysis using either Method 7090 or 7091, and sample extraction using Method 3040 as described in the EPA solid waste regulations SW 846.

Specific Condition 12: Mercury (Hg) shall be testing during initial compliance test using EPA Method 101 (40 CFR 61, Appendix B) or fuel sampling analysis using methods acceptable to the Department.

Specific Condition 13: During performance tests, to determine compliance with the allowable Nox standard, measured NOx emissions at 15 percent oxygen will be adjusted to ISO ambient atmospheric conditions by the following correction factor.

Specific Condition 19: The sources shall comply with all requirements of 40 CFR 60, Subpart GG, and F.A.C. Rule 17-296.800, Standards of Performance for Stationary Gas Turbines.

Test Methods

Specific Condition 14: Test results will be the average of 3 valid runs. The Central District office will be notified at least 30 days in writing in advance of the compliance test(s). The sources shall operate between 95% and 100% of permitted capacity during the compliance test(s) as adjusted for ambient temperature. Compliance test results shall be submitted to the Central District office no later than 45 days after completion.

Compliance Dates

Activity	Related Permit Condition	Unit 1 Date	Unit 2 Date
Initial Startup	8	8/20/94	1/29/95
Notification of Testing	14	9/23/94	3/2/95
Compliance Testing	8, 14	10/20/94 11/3/94* 11/7/94*	4/6-10/95
Submittal of Test Report	14	12/22/94	5/24/95
*KUA received permission from FDEP to retest. Retesting performed on these dates.			

Compliance Test Methods

The compliance testing was done in accordance with the permit requirements listed above. The compliance test methods and results are provided in the test reports provided to the FDEP on the dates in the above table.

Appendix S

Appendix S

Procedures for Startup and Shutdown

Procedures for Startup and Shutdown

After a normal start up is initiated, the time is documented when the turbine starts firing. The turbine then continues with a normal start up and warm up. Time is again documented again when the breaker closes. Upon the generator reaching nine MW, the water injection pump is turned on, and flow is established to the turbine. When the NOx emissions are controlled and stable (20-24 ppm), the time is again documented. The turbine is then released to dispatch the necessary load.

When a shut down occurs, the load on the generator is reduced to nine MW and the water injection pumps are taken out of service (this time is documented). Time is again recorded when the turbine stops firing.

Appendix T

Appendix T

Operation and Maintenance Plan

Operation and Maintenance Plan

Construction permit AC49-205703 does not require an operation and maintenance plan for this facility.

Appendix U

Appendix U

Alternative Methods of Operation

Alternative Methods of Operation

The combustion turbine facility will burn natural gas as the primary fuel and No. 2 distillate fuel oil (0.05 percent sulfur) as a secondary back-up fuel. In the event of non-availability of natural gas (natural gas curtailment), the facility may burn No. 2 distillate fuel oil the entire year, or up to 1,000 hours per year if natural gas is available, with the remainder of the year on natural gas.

As provided for in the permit application instructions (Ref. DEP Form No. 62-210.900(1), page 20), the alternative methods of operation as the result of fuel options are discussed in detail in the Emissions Unit Information Section of the permit application.

Appendix V

Appendix V

Unit Specific Applicable Requirements

Unit Specific Applicable Requirements

Applicable Regulation	Applicable Requirement	Compliance Status	Compliance Method
40 CFR 60.8, Performance tests	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup, the owner or operator shall conduct performance tests in accordance with applicable methods and procedures contained in 40 CFR 60.	Comply	Specific test methods and procedure requirements are outlined in the construction permit.
40 CFR 60.13, Monitoring Requirements	For CEMS subject to this part, the owner or operator shall check the zero and span calibration drifts at least once daily. The zero and span shall be adjusted whenever the 24-hour zero drift or span drift exceeds two times the limits of the performance specification.	Comply	As specified in this section.
40 CFR 60.332, Standard for nitrogen oxides	No owner or operator shall discharge into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of the equation specified in 40 CFR 60.332(a)(1).	Comply	Specific emission limits and compliance methods established in the facility's construction permit.

40 CFR 60.333, Standard for sulfur dioxide	No owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.	Comply	Specific fuel limits and compliance methods established in the facility's construction permit.
40 CFR 60.334, Monitoring of operations	The owner or operator of any stationary gas turbine which uses water injection to control NOx emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and ratio or water to fuel.	Comply	As specified in this section.
	The owner or operator of any stationary gas turbine shall monitor sulfur and nitrogen content as follows: ● For fuel oil from bulk storage tank, the values shall be determined each time fuel is transferred to the storage tank. ● For natural gas (no bulk storage), the values shall be determined and recorded daily.	Comply	For fuel oil, vendor will supply analysis with each delivery. For natural gas, vendor supplied analysis will be used to represent daily values.

	The following periods of excess emissions shall be reported as defined in 40 CFR 60.334 (c)(1): • Any one-hour period where the average water-to-fuel ratio falls below required limits or the nitrogen content of the fuel exceeds allowable limits. • Any daily period during which the sulfur content of the fuel fired exceeds 0.8 percent.	Will comply when applicable	As specified in this section.
40 CFR 60.335, Test methods and procedures	The facility shall comply with the test methods and monitoring procedures defined in these provisions.	Comply	Specific test methods and procedure requirements are outlined in the facility's construction permit.
40 CFR 72.9, Standard requirements	A complete Acid Rain permit application shall be submitted for the affected facility by January 1, 1998.	Will comply when applicable	As specified in this section.
40 CFR 72.21, Submissions	Each submission under the Acid Rain program shall be submitted, signed, and certified by the designated representative.	Will comply when applicable	As specified in this section.

40 CFR 75.3, SUBPART A - General, Compliance dates	Gas or oil fired Acid Rain affected units commencing operation after Nov. 15, 1990 which are not located in an ozone nonattainment area or the ozone transport region shall complete all NOx and CO2 CEMS certification tests by Jan. 1, 1996.	Comply	Completed
40 CFR 75.5, Prohibitions	No owner or operator of an affected Acid Rain unit shall operate the unit without complying with the requirements of 40 CFR 75.2 through 40 CFR 75.67 and appendices A through I of Part 75.	Comply	As specified in this section.
	No owner or operator of an affected unit shall use any alternative monitoring system or reference method without written approval from the DEP.	Comply	As specified in this section.
40 CFR 75.5, Prohibitions (continued)	No owner or operator of an affected unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method except for periods of recertification, or periods when calibration, quality assurance, or maintenance is performed pursuant to 40 CFR 75.21 and Appendix B.	Comply	As specified in this section.
	No owner or operator shall retire or permanently discontinue use of the CEMS, any component thereof, except as allowed in 40 CFR 75.5 (f).	Comply	As specified in this section.

40 CFR 75.10, SUBPART B - Monitoring Provisions, General operating requirements	The owner or operator shall install, certify, operate, and maintain a NOx continuous emission monitoring system (NOx pollutant monitor and an O2 or CO2 diluent gas monitor) with automated DAHS which records NOx concentration, O2 or CO2 concentration, and NOx emission rate.	Comply	As specified in this section.
	The owner or operator shall measure CO2 emissions using a method specified in 40 CFR 75.10 through 75.16 and Appendices E and G.	Comply	As specified in this section.
	The owner or operator shall determine and record the heat input to the affected unit for every hour any fuel is combusted according to the procedures in Appendix F of this subpart.	Comply	See applicable regulations in Appendix F for details.
	The owner or operator shall ensure that each CEMS, and component thereof, is capable of completing a minimum of one cycle of operation for each successive 15-minute interval.	Comply	As specified in this section.
40 CFR 75.11, Specific provisions for monitoring SO2	Gas and oiled fired units shall measure and record SO2 emissions as specified in 40 CFR 75, Appendix D.	Comply	See applicable regulations in Appendix D for details.

40 CFR 75.20, SUBPART C - Operation and Maintenance Requirements, Certification and recertification procedures	The owner or operator shall ensure that each CEMS meets the initial certification requirements as specified in this section including notification and certification application.	Comply	As specified in this section.
	Whenever a replacement, modification, or change in the certified CEMS (including the DAHS and CO2 systems) is made, the owner or operator shall recertify the CEMS, or component thereof, according to the procedures identified in 40 CFR 75.20 (b) and (c).	Will comply when applicable	As specified in this section.
	The owner or operator using the optional SO2 monitoring protocol of Appendix D of this subpart shall ensure that this system meets the certification requirements of 40 CFR 75.20 (g).		As specified in this section.
40 CFR 75.21, Quality assurance and quality control requirements	The provisions of this part are suspended from July 17, 1995 through December 31, 1996. The owner or operator shall operate, calibrate, and maintain each CEMS according to the procedures of 40 CFR 75, Appendix B.		As specified in this section.
40 CFR 75.24, Out-of-control periods	If an out-of-control period occurs to a CEMS, the owner or operator shall take corrective action, as delineated in 40 CFR 75.24 (c) through (e), and repeat tests applicable to the "out-of-control" parameter.	Will comply when applicable	As specified in this section.

40 CFR 75.30 SUBPART D - Missing Data Substitution Procedures	The owner or operator shall provide substitute data according to the missing data procedures provided in 40 CFR 75.30 through 75.36.	Comply	As specified in these sections.
40 CFR 75.51, SUBPART F - Recordkeeping Requirements, General recordkeeping provisions for specific situations	The owner or operator shall comply with the recordkeeping requirements of 40 CFR 75.51 (c)(1) through (3) when combusting natural gas and fuel oil.	Comply	As specified in this section.
40 CFR 75.52, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.52 (a)(1) through (3) and 40 CFR 75.52 (a)(5) through (7).	Comply	As specified in this section.
40 CFR 75.53, Monitoring Plan	The owner or operator shall prepare and maintain a monitoring plan pursuant to all applicable portions of this section.	Comply	As specified in this section.
40 CFR 75.54, General recordkeeping provisions	The owner or operator shall maintain a file of all applicable measurements, data, reports, and other information required by 40 CFR 75 at the source for at least three (3) years according to the provisions of this section.	Comply	As specified in these sections.
40 CFR 75.55, General recordkeeping provisions for specific situations	For SO2 emission records, The owner or operator shall record information as required in 40 CFR 75.55 (c) in lieu of the provisions of 40 CFR 75.54 (c),	Comply	As specified in this section.

40 CFR 75.56, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.56 (a)(1) through (3) and 40 CFR 75.56 (a)(5) through (7).	Comply	As specified in this section.
40 CFR 75.60, SUBPART G - Reporting Requirements, General Provisions	The designated representative shall comply with all reporting requirements of this section for all submissions, and follow the procedures of 40 CFR 75.60 (c) for any claims of confidential data.	Comply	As specified in this section.
40 CFR 75.61, Notifications	The designated representative shall submit proper notifications of specified data in this section.	Comply	As specified in this section.
40 CFR 75.62, Monitoring plan	The designated representative shall submit the monitoring plan no later than 45 days prior to the first scheduled certification test except as noted in this section.	Comply	As specified in this section.
40 CFR 75.64, Quarterly reports	The designated representative shall electronically submit the data specified in 40 CFR 75.64 (a), (b), and (c) on a quarterly basis.	Comply	As specified in this section.
40 CFR 75, Appendix A	The owner or operator shall adhere to all applicable specifications and test procedures identified in this section.	Comply	As specified in this section.
40 CFR 75, Appendix B	The owner or operator shall adhere to all applicable quality assurance and quality control procedures identified in this section.	Comply	As specified in this section.

40 CFR 75, Appendix C	The owner or operator shall adhere to all applicable missing data estimation procedures identified in this section.	Comply	As specified in this section.
40 CFR 75, Appendix D	The owner or operator shall adopt the protocol for SO2 emissions monitoring, and adhere to all applicable requirements, as identified in this section.	Comply	As specified in this section.
40 CFR 75, Appendix F	The owner or operator shall adhere to all applicable conversion procedures identified in this section.	Comply	As specified in this section.
40 CFR 75, Appendix H, Revised Traceability Protocol No. 1	The owner or operator shall adhere to all applicable requirements identified in this section.	Comply	As specified in this section.
40 CFR 75, Appendix J	The owner or operator shall adhere to all applicable requirements identified in this appendix.	Comply	As specified in this section.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.	Will comply when applicable	As specified in this section.
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130	Will comply when applicable	As specified in this section.

F.A.C. 62-296.405	The owner must submit a written report of excess emissions for each unit requiring NSPS monitoring each calendar quarter to the FDEP.	Comply	Reporting.
F.A.C. 62-297.310, General Test Requirements	Compliance tests for mass emission limitations shall consist of three complete and separate determinations of the total air pollutant emission rate, and three complete and separate determinations of any applicable process variables according to the test procedures delineated in this rule.	Comply	As specified in this section.
Permit Number: AC 49-205703	The facility will comply with all operating restrictions, performance testing, and emission limits incorporated in the referenced permit.	Comply	As specified in this section.

Appendix W

Appendix W

Compliance Assurance Monitoring Plan

Compliance Assurance Monitoring Plan

Before the Clean Air Act was re-authorized in 1990, the Agency and State and local air pollution offices had concerns that some sources of air pollution were not in compliance with emission control regulations and, as a result, air quality was being adversely affected. Title VII, enforcement provisions, of the Clean Air Act Amendments of 1990 authorized the Agency to develop regulations requiring permitted facilities to monitor the adequacy of emission control equipment and operations. In September 1993, EPA proposed an enhanced monitoring rule, a new Part 64 to title 40 of the Code of Federal Regulations, that set general monitoring criteria to be followed in demonstrating continuous compliance.

In April 1995, the Agency determined to revisit the proposed Part 64 enhanced monitoring rule to allow review of other regulatory approaches to enhanced monitoring. The EPA received an extension of the court-ordered deadline until July 1, 1996, to allow time for stakeholder involvement in development of a new rule. The stakeholders currently involved in this process include industry representatives, State and local agencies, and environmental groups. The result of the process is a redrafted rule, named compliance assurance monitoring or CAM. The CAM rule is designed to satisfy the requirements for monitoring and compliance certification in titles V, the operating permits program, and title VII of the 1990 Clean Air Act Amendments.

The CAM rule reproposal date (originally scheduled for December 1995) and the promulgation date of July 1, 1996, will likely be delayed from 7 to 9 months as a result of the Agency dealing with the significant issues raised in the comments on the draft rule and the recent government shutdown.

Compliance monitoring will be conducted as detailed in the Emissions Unit Information portion of this application, and as required by construction permit AC49-205703. If, after the approval and promulgation of the CAM rule, more restrictive compliance monitoring is required, the necessary steps will be undertaken to ensure the facility meets all monitoring requirements.

Appendix X

Appendix X

Acid Rain Application

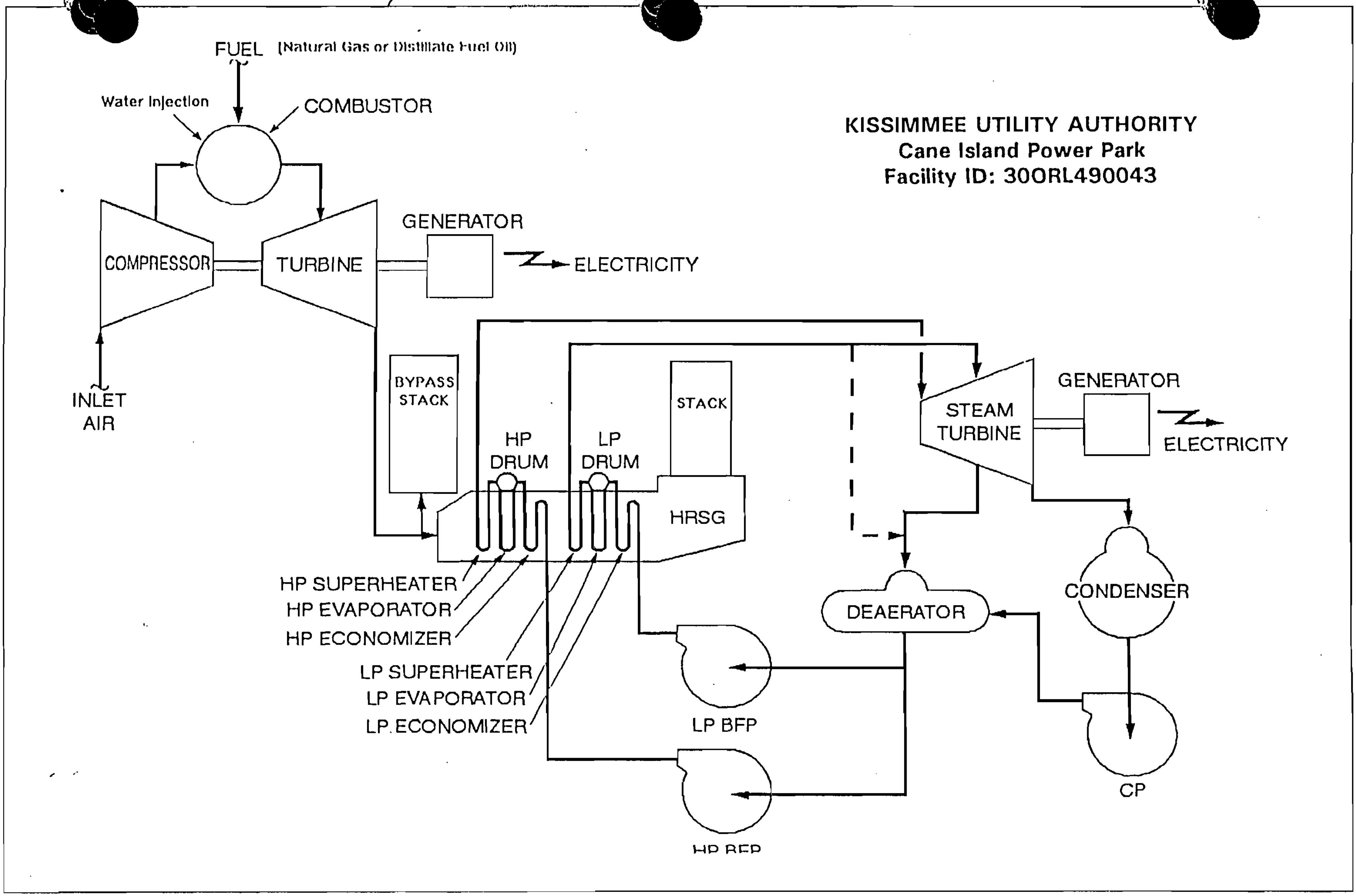
Acid Rain Application

The acid rain application will be submitted in accordance with F.A.C. Rule 62-214.320(b) for new units.

Appendix Y

Appendix Y

Process Flow Diagram



120 MW Combined Cycle Combustion Turbine
Process Flow Diagram
(Ref DEP Form No. 62-210.900(1))

Appendix Z

Appendix Z

Detailed Description of Control Equipment

Detailed Description of Control Equipment

1)Low NOx Burner: A technology that uses a two-stage combustor that premixes a portion of the air and fuel in the first stage and the remaining air and fuel are injected into the second stage. This two-stage process ensures good mixing of the air and fuel, and minimizes the amount of air required which results in low NOx emissions.

2)Use of low sulfur fuel oil (0.05 percent) and the use of natural gas.

3)Water Injection: A control technology used to limit NOx emissions. The thermal NOx contribution to total NOx emission is reduced by lowering the combustion temperature through the use of water injection in the combustion zones of the combustion turbine. Water injection will be used only during oil firing.

Appendix AA

Appendix AA

Description of Stack Sampling Facilities

(Excerpt from unit 2 stack testing report)

Testing for the lower load levels called for in Subpart GG were conducted on April 6 and 7, 1995. The 75% load test was conducted on April 6 from 2120 - 2300. The average output during this time period was 69.1 Mega Watts (MW). Middle and low load tests were conducted on April 7, 1995. Middle load was from 900 - 1040 at 57.01 MW output and low load was from 1100 - 1240 at 44.1 MW output.

2.2 Unit #2 Fuel Oil

The #2 fuel oil testing of Unit #2 was conducted on April 8 and 10, 1995. Base load testing was accomplished in three one hour test runs for PM_{10}, and 64 minute runs for NO_x, O_2, CO, CO_2 and THC, at an average of 77.1 MW output, all three runs were conducted on April 10, 1995. On April 8, 1995 all test runs for the Subpart GG requirements were conducted. Low Load testing was conducted from 1300 - 1440 at an average output of 59.9 MW. Middle-Load testing was from 1500 - 1640 with a 67 MW output. 75% test condition runs were from 1700 - 1840 at 72 MW.

3.0 PROJECT SUMMARY

3.1 Coordination

Power Generation Technologies (PGT) retained the testing services of Schreiber, Grana & Yonley, Inc. as per the proposal dated March 2, 1995 to perform the compliance and load rate testing, as required by Subpart GG, at the Cane Island facility. The test team leader for Schreiber, Grana & Yonley, Inc. was Mr. David Stone. The primary test coordinator for PGT was Mr. Keith Gronewald.

3.2 Test Description

The test was conducted to show compliance with the limits specified in the FDEP permit for the facility. Using the procedures set forth in Method 20, three tests for NO_x, O_2, CO, CO_2, THC, and PM_{10} were performed at base load conditions for each fuel. Each test was conducted for 60 minutes of total sample time. Prior to and immediately following each sample run, the sample system was checked for bias and drift using Protocol One calibration gases. Testing for the Subpart GG requirements were performed for a total run time of 20 minutes each. Test parameters for these runs were NO_x, O_2 and CO_2. The sample system bias and drift were checked as discussed above. Each post run system check served as the pre-test system check for the next run. The average run results were then corrected for bias and drift. All of the test results are expressed on a dry basis. THC results were corrected to dry using the moisture results from the PM_{10} sample train.

3.2.1 Test Procedures

The instrumentation and all sampling and analytical procedures utilized by Schreiber, Grana and Yonley, Inc. for the EPA test methods conform with all the requirements of Appendix A Methods 1, 2, 3, 4, 5, 10, 20 and 25A (40 CFR 60).

All testing was conducted on the stack using the reference analyzers and test procedures discussed below. The extractive monitors require that the effluent gas sample be conditioned to eliminate any possible interference (i.e., water vapor and particulate matter) before being transported and injected into the analyzer. All components of the sampling system are either stainless steel, glass, or Teflon. A heated probe with an in-stack particulate filter, a heated sample line, moisture removal system, and sample pumps were used to deliver representative samples of the flue gas to the analyzer.

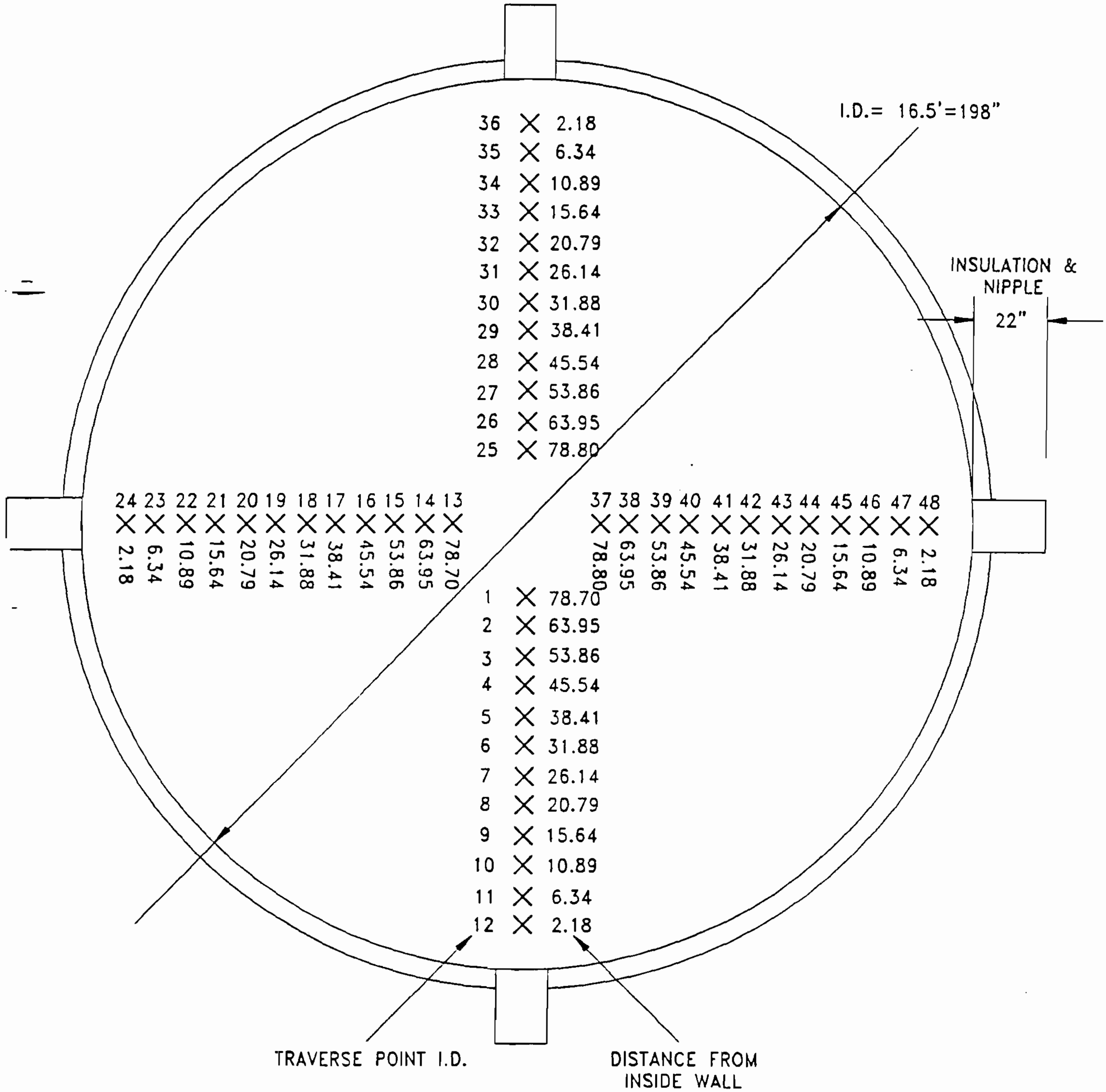
Prior to the start of testing, Method 20 requires that a 48 point traverse of the stack be performed. This traverse is to choose the eight lowest concentrations of 0_2 so that they can be used for the sample runs. The traverse is to be performed while the turbine is operating at it's lowest output. SGY performed the traverse while the turbine was operating at 44 MW output on April 6, 1995 from 1100 - 1330. Each of the 48 points was sampled for two minutes. The O_2 present levels stayed within 0.10% throughout the sample test. Figure 1 gives a graphical representation of the 48 sample point locations for the O_2 traverse.

3.2.2 Extractive Monitor System

The sampling probe was moved to each of the eight required traverse points every eight minutes during each base load test run. For the Subpart GG test runs, the probe was moved every two minutes (due to the averaging requirements of the data logger, twenty minute test runs were conducted, that required point numbers one and eight to be sampled at four minutes). The probe assembly is constructed of 316 stainless steel and is heated electrically to maintain the sample temperature above the dew point. On the back of the probe is a heated three-way valve to allow calibration gases to be injected directly into the sample system to perform bias checks.

Moisture is removed from the gas sample by a KWW Gas Sample Conditioner. In the electronic gas sample conditioner, the sample gas is cooled to +2 degrees Celsius in a heat exchanger. The condensate precipitated from the sample gas is deposited in a precipitation vessel.

OXYGEN TRAVERSE POINT LAYOUT



OXYGEN TRAVERSE POINT LAYOUT KISSIMMEE UTILITY AUTHORITY 6075 OLD TAMPA HIGHWAY INTERCESSION CITY, FLORIDA				SCHREIBER & GRANA YONLEY INCORPORATED ENVIRONMENTAL ENGINEERS
CHECKED BY:	DRAWN BY:	DATE DRAWN:	DRAWING #:	REVISION:
	AML	5-22-95	PG3444-2	

The sample acquisition/sample conditioning system also includes two calibration injection ports: (1) immediately upstream of the system for system linearity checks, and (2) at the outlet of the probe for sampling system bias and calibration drift checks. This arrangement provides both ease in checking the analyzer performance and a means of evaluating the entire monitoring system.

Nitrogen Oxide Testing

Nitrogen Oxides emissions were sampled using a Thermo Environmental (TECO) model 42 analyzer. Gas enters the Model 42, flows through the sample capillary to the NO_2 to NO Converter then to the reaction chamber. There the NO reacts with ozone to produce a characteristic chemiluminescence. Reacted gas is drawn from the reaction chamber through the internal pump.

The Model 42 is a single chamber, single photomultiplier tube design and automatically cycles between the NO and NO_x modes. Signals from the photomultiplier tube are conditioned and then fed to the microprocessor where a sophisticated mathematical algorithm is utilized to calculate three independent outputs: NO, NO_2, and NO_x.

Oxygen Testing

A Thermox model stack gas analyzer was used to sample oxygen. The analyzer utilizes a closed end zirconium oxide sensor to measure the partial pressure oxygen concentration in a convection loop. A small portion of sample passes the cell which responds according to the following equation:

$$E = AT \log \frac{0.209}{(O_2)x}$$

where E is volts, A is a gas constant, T is absolute temperature and $(O_2)x$ is the unknown oxygen concentration in the sample.

Carbon Monoxide Testing

Carbon Monoxide analysis was accomplished using a TECO model 48 Gas Filter Correlation analyzer. Radiation from an infrared source is chopped and then passed through a gas filter which alternates between CO and N_2 due to rotation of the filter wheel. The radiation then passes through a narrow bandpass filter and a multiple optical pass sample cell where absorption by the sample gas occurs. The IR radiation exits the sample cell and falls on a solid state IR detector.

The CO gas filter acts to produce a reference beam which cannot be further affected by CO in the sample chamber. The N_2 side of the filter wheel is transparent to IR radiation and therefore produces a measure beam which can be absorbed by CO. The chopped detector signal is modulated by the alternation between the two gas filters with an amplitude proportional to the concentration of CO in the sample chamber. Other gases do not cause modulation of the detector signal since they absorb the reference and measure beams equally. Thus, the Gas Filter Correlation System responds solely to CO.

Carbon Dioxide Testing

The Carbon Dioxide analyzer used was a FUJI model ZRH Infrared Gas analyzer. Infrared light emitting from an infrared source is intermitted by a chopper driven by a chopper motor in a certain frequency, then led into a measuring cell. The infrared light beam is partially absorbed into the measured component in the measuring cell and the unabsorbed portion reaches a detector which is provided with a front chamber and a rear chamber, both filled with carbon dioxide. Infrared light is led into the detector, the gases filling in both chambers absorb the light and expand.

Since the detector is designed to produce an expansion difference between the front and rear chambers, a slight gas flow is produced in a mass-flow sensor and this slight flow generates output voltage in the sensor.

Data Acquisition

A Environmental Systems Corporation (ESC) electronic data logger was used to collect and store the analyzer output data. The data logger is a point storage system that collects and stores data in voltage output form and then converts the voltage to parts per million (ppm) or percent (%). The ppm and percent values were continuously printed on a dot matrix printer.

Total Hydrocarbon Testing

Total Hydrocarbon (THC) testing was performed using a Ratfisch model RS-55CA Flame Ionization Detector (FID). The gas sample is injected into a pure hydrogen flame which burns the hydrocarbons in the sample. When the hydrocarbon is burned it releases electrically charged ions which are then attracted to collection plates located in the FID. The electrical energy is absorbed by the collection plates and then amplified to provide an output voltage.

Before the gas sample entered into the moisture removal system, a "T" connection was installed and a separate heated sample line was connected to it. This heated line was used to maintain the gas sample temperature above dew point and to transport the gas sample to the FID. All THC data was recorded as wet values and then corrected to dry using the moisture results obtained from the Method 4 sample runs. The analyzer was calibrated on a 0 to 100 ppm range using propane. All results are reported as propane.

Data Acquisition of Total Hydrocarbon Data

A Rustrak Ranger II electronic data logger was used to collect and store the THC analyzer output data. The data logger is a point storage system that stores data in voltage output form and then converts the voltage to parts per million (ppm). At the end of the test day, all data was loaded onto the hard drive of a Compaq notebook computer. Data reduction is accomplished using the Pronto software program that accompanies the Rustrak Ranger II. Pronto generates a graph of the data to be analyzed, which allows the operator to obtain test run averages and calibration values.

3.2.3 Isokinetic Sample System

Methods for testing of all isokinetic sample runs are located in Appendix A (40 CFR 60). The procedures and equipment used conformed with all requirements stated in the above referenced methods.

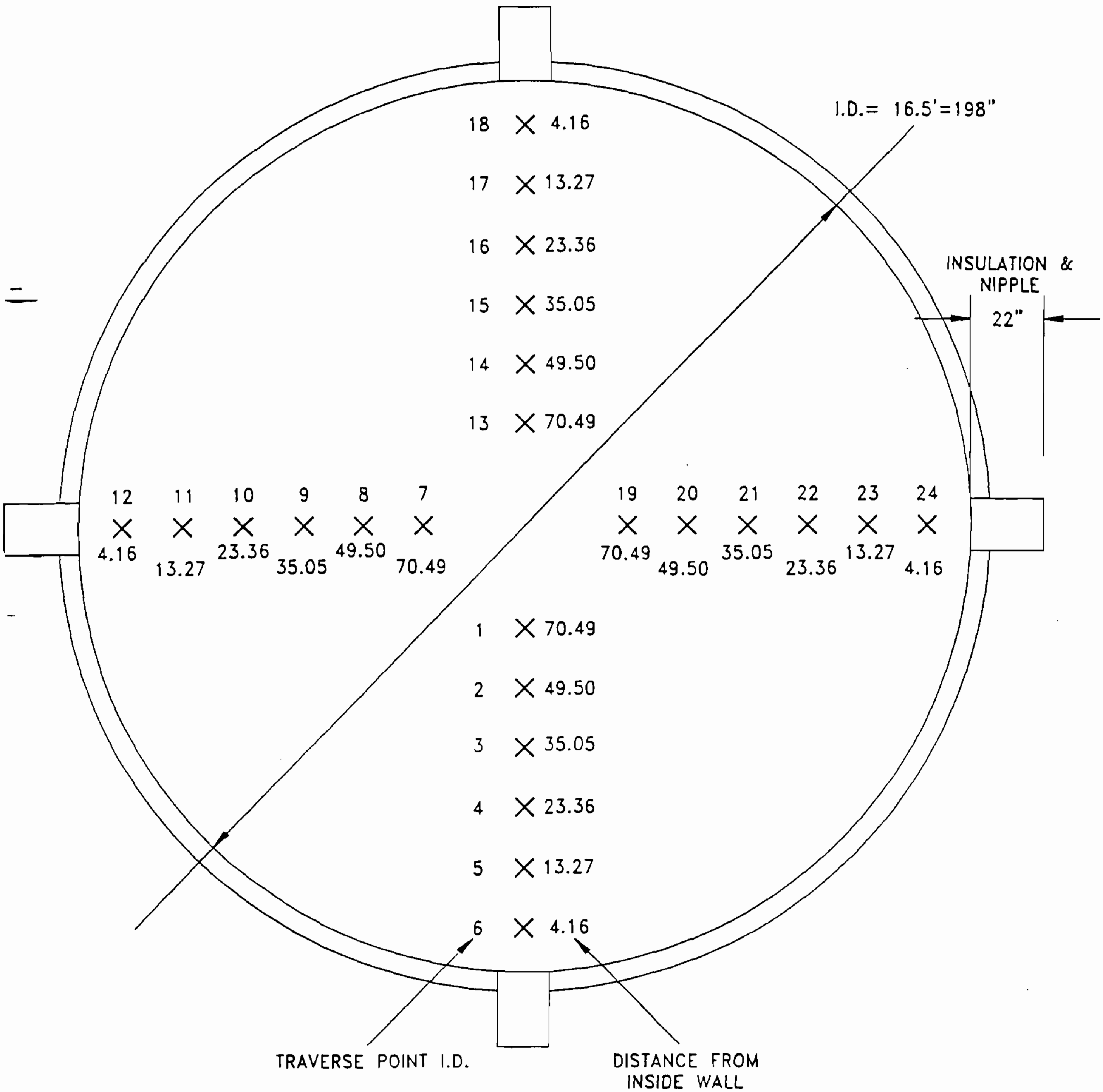
Traverse Location

Traverse point locations were determined using Method 1 (App. A, 40 CFR 60). Four horizontal traverse ports were used to divide the cross-sectional area of the stack into equal representational areas for sampling; 24 points for Method 2 and Method 5 tests, and 48 points for the extractive analyzer testing. Figure 2 gives a graphical representation of the sample point locations.

Velocity Flow

Velocity and flow rate measurements were determined using Method 2 (App. A, 40 CFR 60). An "S"-type pitot tube probe per method specifications was used to measure the velocity and pressure of the stack gas at each sampling location. The velocity and pressure were measured using a Neotronics digital pressure transducer. The pitot tube was calibrated based on geometric considerations as specified in Method 2.

METHOD 5 TRAVERSE POINT LAYOUT



METHOD 5 TRAVERSE POINT LAYOUT KISSIMMEE UTILITY AUTHORITY 6075 OLD TAMPA HIGHWAY INTERCESSION CITY, FLORIDA					SCHREIBER GRANA & YONLEY INCORPORATED ENVIRONMENTAL ENGINEERS
CHECKED BY:	DRAWN BY:	DATE DRAWN:	DRAWING #:	REVISION:	
	AML	5-22-95	PG3444-1		

The temperature of the stack gas was measured using K-type thermocouples and digital temperature readouts. The temperature was recorded on the Method 5 sampling data sheet. The temperatures were arithmetically averaged and used to calculate the volumetric flow rates at actual and standard conditions.

Moisture Content

Stack gas moisture content was determined using the procedures outlined in Method 4 (App. A, 40 CFR 60). The Method 4 sampling was conducted in conjunction with each Method 5 sample run. The moisture was determined by gravimetrically measuring the weight gain of the chilled impingers over the length of the sampling runs. The specific procedures are described as follows. Four ball topped impingers in an ice bath were connected to the back of the filter holder with a glass connector. The first and second impingers contained 100 ml of deionized distilled water. The third impinger was left empty, and the fourth contained 200 grams of indicating silica gel. Each impinger was weighed intact to the nearest 0.1 gram to determine the moisture gained during the test.

All fittings in the system were rigid glass ball sockets to prevent leakage. A leak check was performed per Method 5 prior to and after each sampling run to ensure there was no dilution air in-leakage.

Particulate Matter

Method 5 (App. A, 40 CFR 60) was used in the determination of Particulate Matter (PM). The sample probe starts with a stainless steel nozzle. The nozzle is selected to sample the gas stream at isokinetic conditions. A 316 stainless steel probe liner, electrically heated to maintain the temperature above the dew point, was used to transport the sample to a filter. The sample then passed through a pre-weighed glass fiber filter that was also heated.

After each sample run, the filter was recovered and placed into it's original petri dish. The nozzle, liner, and glass filter holder were then rinsed with optima grade acetone. The filter and rinse were then transported back to the SGY laboratory in St. Louis where they were conditioned in a desiccator. The samples were weighed every 6 hours until a constant final weight was achieved. All PM results are reported as PM_{10} per FDEP requirements.

Visible Emissions

Visible emission readings for opacity were taken during every base load test. Randy Galati, a qualified observer, followed the procedures outlined in Method 9 (App. A, 40 CFR 60). A copy of his certificate can be found in Appendix G of this report.

3.3 Operating Conditions During Tests

All test conditions and process operating parameters were within required conditions as stated in Subpart GG (40 CFR 60) for the facility as confirmed by Mr. Tom Short of General Electric, the turbine manufacturer's on site representative.

4.0 COMMENTS

This report is an amended version of the original report, dated May 23, 1995, that was submitted to the FDEP and to KUA. This revision (Revision One) will supersede the original report. All changes to the report and Appendices are included in this revision. Appendix C is replaced by this revision as well as the report text. Table 1 of the original report is replaced by Tables 1 and 1A of this revision.

The revision of the report was requested by the FDEP after review by Gary Kuberski and Charles M. Collins. On July 13, 1995 Schreiber, Grana & Yonley, Inc. was informed, in a letter from the FDEP, that there were several problems with the report. Of the six reasons listed in the letter, four of these were determined to be error of omissions by Schreiber, Grana & Yonley, Inc. personnel. Although all of the required results could be obtained from the data provided in the Appendices it was not included in the original table. Due to this error of omission this revised report was produced.

In the letter from the FDEP, reason #3 concerned the VOC emission presentation. The original report presented the results on parts per million (ppm) carbon as propane basis, although the permit states that results be converted to VOC lb/hr. Gary Kuberski of FDEP stated in a phone conversation to David Stone of Schreiber, Grana & Yonley, Inc. that a conversion factor based on the fuel used would need to be applied. Mr. Stone asked that a copy of the formula be sent to him so that he could convert the values to the proper standard. On August 3, 1995 Mr. Kuberski contacted Mr. Stone by phone, he informed Mr. Stone that a conversion factor could not be determined by FDEP. Mr. Kuberski went on to say that the values could be reported as ppm carbon as propane and they would be accepted. A copy of the FDEP letter dated July 13, 1995 is attached to this report for reference information.

Appendix BB

Appendix BB

Procedures for Startup and Shutdown

Procedures for Startup and Shutdown

After a normal start up is initiated, the time is documented when the turbine starts firing. The turbine then continues with a normal start up and warm up. Time is again documented again when the breaker closes. Upon the generator reaching 60 MW, the water injection pump is turned on (fuel oil only), and flow is established to the turbine. When the NOx emissions are controlled and stable (20-24 ppm), the time is again documented. The turbine is then released to dispatch the necessary load.

When a shut down occurs, the load on the generator is reduced to 60 MW and the water injection pumps are taken out of service (fuel oil only-this time is documented). Time is again recorded when the turbine stops firing.

Appendix CC

Appendix CC

Operation and Maintenance Plan

Operation and Maintenance Plan

Construction permit AC49-205703 does not require an operation and maintenance plan for this facility.

Appendix DD

Appendix DD

Alternative Methods of Operation

Alternative Methods of Operation

The combustion turbine facility will burn natural gas as the primary fuel and No. 2 distillate fuel oil (0.05 percent sulfur) as a secondary back-up fuel. In the event of non-availability of natural gas (natural gas curtailment), the facility may burn No. 2 distillate fuel oil the entire year, or up to 1,000 hours per year if natural gas is available, with the remainder of the year on natural gas.

As provided for in the permit application instructions (Ref. DEP Form No. 62-210.900(1), page 20), the alternative methods of operation as the result of fuel options are discussed in detail in the Emissions Unit Information Section of the permit application.

Appendix EE

Appendix EE

Unit Specific Applicable Requirements

Unit Specific Applicable Requirements

Applicable Regulation	Applicable Requirement	Compliance Status	Compliance Method
40 CFR 60.8, Performance tests	Within 60 days after achieving the maximum production rate, but not later than 180 days after initial startup, the owner or operator shall conduct performance tests in accordance with applicable methods and procedures contained in 40 CFR 60.	Comply	Specific test methods and procedure requirements are outlined in the construction permit.
40 CFR 60.13, Monitoring Requirements	For CEMS subject to this part, the owner or operator shall check the zero and span calibration drifts at least once daily. The zero and span shall be adjusted whenever the 24-hour zero drift or span drift exceeds two times the limits of the performance specification.	Comply	As specified in this section.
40 CFR 60.332, Standard for nitrogen oxides	No owner or operator shall discharge into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of the equation specified in 40 CFR 60.332(a)(1).	Comply	Specific emission limits and compliance methods established in the facility's construction permit.

40 CFR 60.333, Standard for sulfur dioxide	No owner or operator shall burn in any stationary gas turbine any fuel which contains sulfur in excess of 0.8 percent by weight.	Comply	Specific fuel limits and compliance methods established in the facility's construction permit.
40 CFR 60.334, Monitoring of operations	The owner or operator of any stationary gas turbine which uses water injection to control NOx emissions shall install and operate a continuous monitoring system to monitor and record the fuel consumption and ratio or water to fuel.	Comply	As specified in this section.
	The owner or operator of any stationary gas turbine shall monitor sulfur and nitrogen content as follows: • For fuel oil from bulk storage tank, the values shall be determined each time fuel is transferred to the storage tank. • For natural gas (no bulk storage), the values shall be determined and recorded daily.	Comply	For fuel oil, vendor will supply analysis with each delivery. For natural gas, vendor supplied analysis will be used to represent daily values.

	The following periods of excess emissions shall be reported as defined in 40 CFR 60.334 (c)(1): • Any one-hour period where the average water-to-fuel ratio falls below required limits or the nitrogen content of the fuel exceeds allowable limits. • Any daily period during which the sulfur content of the fuel fired exceeds 0.8 percent.	Will comply when applicable	As specified in this section.
40 CFR 60.335, Test methods and procedures	The facility shall comply with the test methods and monitoring procedures defined in these provisions.	Comply	Specific test methods and procedure requirements are outlined in the facility's construction permit.
40 CFR 72.9, Standard requirements	A complete Acid Rain permit application shall be submitted for the affected facility by January 1, 1998.	Will comply when applicable	As specified in this section.
40 CFR 72.21, Submissions	Each submission under the Acid Rain program shall be submitted, signed, and certified by the designated representative.	Will comply when applicable	As specified in this section.

40 CFR 75.3, SUBPART A - General, Compliance dates	Gas or oil fired Acid Rain affected units commencing operation after Nov. 15, 1990 which are not located in an ozone nonattainment area or the ozone transport region shall complete all NOx and CO2 CEMS certification tests by Jan. 1, 1996.	Comply	Completed
40 CFR 75.5, Prohibitions	No owner or operator of an affected Acid Rain unit shall operate the unit without complying with the requirements of 40 CFR 75.2 through 40 CFR 75.67 and appendices A through I of Part 75.	Comply	As specified in this section.
	No owner or operator of an affected unit shall use any alternative monitoring system or reference method without written approval from the DEP.	Comply	As specified in this section.
40 CFR 75.5, Prohibitions (continued)	No owner or operator of an affected unit shall disrupt the continuous emission monitoring system, any portion thereof, or any other approved emission monitoring method except for periods of recertification, or periods when calibration, quality assurance, or maintenance is performed pursuant to 40 CFR 75.21 and Appendix B.	Comply	As specified in this section.
	No owner or operator shall retire or permanently discontinue use of the CEMS, any component thereof, except as allowed in 40 CFR 75.5 (f).	Comply	As specified in this section.

40 CFR 75.10, SUBPART B - Monitoring Provisions, General operating requirements	The owner or operator shall install, certify, operate, and maintain a NOx continuous emission monitoring system (NOx pollutant monitor and an O2 or CO2 diluent gas monitor) with automated DAHS which records NOx concentration, O2 or CO2 concentration, and NOx emission rate.	Comply	As specified in this section.
	The owner or operator shall measure CO2 emissions using a method specified in 40 CFR 75.10 through 75.16 and Appendices E and G.	Comply	As specified in this section.
	The owner or operator shall determine and record the heat input to the affected unit for every hour any fuel is combusted according to the procedures in Appendix F of this subpart.	Comply	See applicable regulations in Appendix F for details.
	The owner or operator shall ensure that each CEMS, and component thereof, is capable of completing a minimum of one cycle of operation for each successive 15-minute interval.	Comply	As specified in this section.
40 CFR 75.11, Specific provisions for monitoring SO2	Gas and oiled fired units shall measure and record SO2 emissions as specified in 40 CFR 75, Appendix D.	Comply	See applicable regulations in Appendix D for details.

40 CFR 75.20, SUBPART C - Operation and Maintenance Requirements, Certification and recertification procedures	The owner or operator shall ensure that each CEMS meets the initial certification requirements as specified in this section including notification and certification application.	Comply	As specified in this section.
	Whenever a replacement, modification, or change in the certified CEMS (including the DAHS and CO2 systems) is made, the owner or operator shall recertify the CEMS, or component thereof, according to the procedures identified in 40 CFR 75.20 (b) and (c).	Will comply when applicable	As specified in this section.
	The owner or operator of a by-pass stack CEMS shall comply with all the requirements of 40 CFR 75.20 (a), (b), and (c) except only one nine-run relative accuracy test audit for certification or recertification of the flow monitor needs to be performed.	Comply	Applies to Unit 2 only.
	The owner or operator using the optional SO2 monitoring protocol of Appendix D of this subpart shall ensure that this system meets the certification requirements of 40 CFR 75.20 (g).		As specified in this section.
40 CFR 75.21, Quality assurance and quality control requirements	The provisions of this part are suspended from July 17, 1995 through December 31, 1996. The owner or operator shall operate, calibrate, and maintain each CEMS according to the procedures of 40 CFR 75, Appendix B.		As specified in this section.

40 CFR 75.24, Out-of-control periods	If an out-of-control period occurs to a CEMS, the owner or operator shall take corrective action, as delineated in 40 CFR 75.24 (c) through (e), and repeat tests applicable to the "out-of-control" parameter.	Will comply when applicable	As specified in this section.
40 CFR 75.30 SUBPART D - Missing Data Substitution Procedures	The owner or operator shall provide substitute data according to the missing data procedures provided in 40 CFR 75.30 through 75.36.	Comply	As specified in these sections.
40 CFR 75.51, SUBPART F - Recordkeeping Requirements, General recordkeeping provisions for specific situations	The owner or operator shall comply with the recordkeeping requirements of 40 CFR 75.51 (c)(1) through (3) when combusting natural gas and fuel oil.	Comply	As specified in this section.
40 CFR 75.52, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.52 (a)(1) through (3) and 40 CFR 75.52 (a)(5) through (7).	Comply	As specified in this section.
40 CFR 75.53, Monitoring Plan	The owner or operator shall prepare and maintain a monitoring plan pursuant to all applicable portions of this section.	Comply	As specified in this section.

40 CFR 75.54, General recordkeeping provisions	The owner or operator shall maintain a file of all applicable measurements, data, reports, and other information required by 40 CFR 75 at the source for at least three (3) years according to the provisions of this section.	Comply	As specified in these sections.
40 CFR 75.55, General recordkeeping provisions for specific situations	For SO2 emission records, The owner or operator shall record information as required in 40 CFR 75.55 (c) in lieu of the provisions of 40 CFR 75.54 (c),	Comply	As specified in this section.
40 CFR 75.56, Certification, quality assurance, and quality control record provisions	The owner or operator shall record the applicable information listed in 40 CFR 75.56 (a)(1) through (3) and 40 CFR 75.56 (a)(5) through (7).	Comply	As specified in this section.
40 CFR 75.60, SUBPART G - Reporting Requirements, General Provisions	The designated representative shall comply with all reporting requirements of this section for all submissions, and follow the procedures of 40 CFR 75.60 (c) for any claims of confidential data.	Comply	As specified in this section.
40 CFR 75.61, Notifications	The designated representative shall submit proper notifications of specified data in this section.	Comply	As specified in this section.
40 CFR 75.62, Monitoring plan	The designated representative shall submit the monitoring plan no later than 45 days prior to the first scheduled certification test except as noted in this section.	Comply	As specified in this section.

40 CFR 75.64, Quarterly reports	The designated representative shall electronically submit the data specified in 40 CFR 75.64 (a), (b), and (c) on a quarterly basis.	Comply	As specified in this section.
40 CFR 75, Appendix A	The owner or operator shall adhere to all applicable specifications and test procedures identified in this section.	Comply	As specified in this section.
40 CFR 75, Appendix B	The owner or operator shall adhere to all applicable quality assurance and quality control procedures identified in this section.	Comply	As specified in this section.
40 CFR 75, Appendix C	The owner or operator shall adhere to all applicable missing data estimation procedures identified in this section.	Comply	As specified in this section.
40 CFR 75, Appendix D	The owner or operator shall adopt the protocol for SO2 emissions monitoring, and adhere to all applicable requirements, as identified in this section.	Comply	As specified in this section.
40 CFR 75, Appendix F	The owner or operator shall adhere to all applicable conversion procedures identified in this section.	Comply	As specified in this section.
40 CFR 75, Appendix H, Revised Traceability Protocol No. 1	The owner or operator shall adhere to all applicable requirements identified in this section.	Comply	As specified in this section.

40 CFR 75, Appendix J	The owner or operator shall adhere to all applicable requirements identified in this appendix.	Comply	As specified in this section.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.	Will comply when applicable	As specified in this section.
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130	Will comply when applicable	As specified in this section.
F.A.C. 62-297.310, General Test Requirements	Compliance tests for mass emission limitations shall consist of three complete and separate determinations of the total air pollutant emission rate, and three complete and separate determinations of any applicable process variables according to the test procedures delineated in this rule.	Comply	As specified in this section.
F.A.C. 62-296.405	The owner must submit a written report of excess emissions for each unit requiring NSPS monitoring each calendar quarter to the FDEP.	Comply	Reporting.
Permit Number: AC 49-205703	The facility will comply with all operating restrictions, performance testing, and emission limits incorporated in the referenced permit.	Comply	As specified in this section.

Appendix FF

Appendix FF

Compliance Assurance Monitoring Plan

Compliance Assurance Monitoring Plan

Before the Clean Air Act was re-authorized in 1990, the Agency and State and local air pollution offices had concerns that some sources of air pollution were not in compliance with emission control regulations and, as a result, air quality was being adversely affected. Title VII, enforcement provisions, of the Clean Air Act Amendments of 1990 authorized the Agency to develop regulations requiring permitted facilities to monitor the adequacy of emission control equipment and operations. In September 1993, EPA proposed an enhanced monitoring rule, a new Part 64 to title 40 of the Code of Federal Regulations, that set general monitoring criteria to be followed in demonstrating continuous compliance.

In April 1995, the Agency determined to revisit the proposed Part 64 enhanced monitoring rule to allow review of other regulatory approaches to enhanced monitoring. The EPA received an extension of the court-ordered deadline until July 1, 1996, to allow time for stakeholder involvement in development of a new rule. The stakeholders currently involved in this process include industry representatives, State and local agencies, and environmental groups. The result of the process is a redrafted rule, named compliance assurance monitoring or CAM. The CAM rule is designed to satisfy the requirements for monitoring and compliance certification in titles V, the operating permits program, and title VII of the 1990 Clean Air Act Amendments.

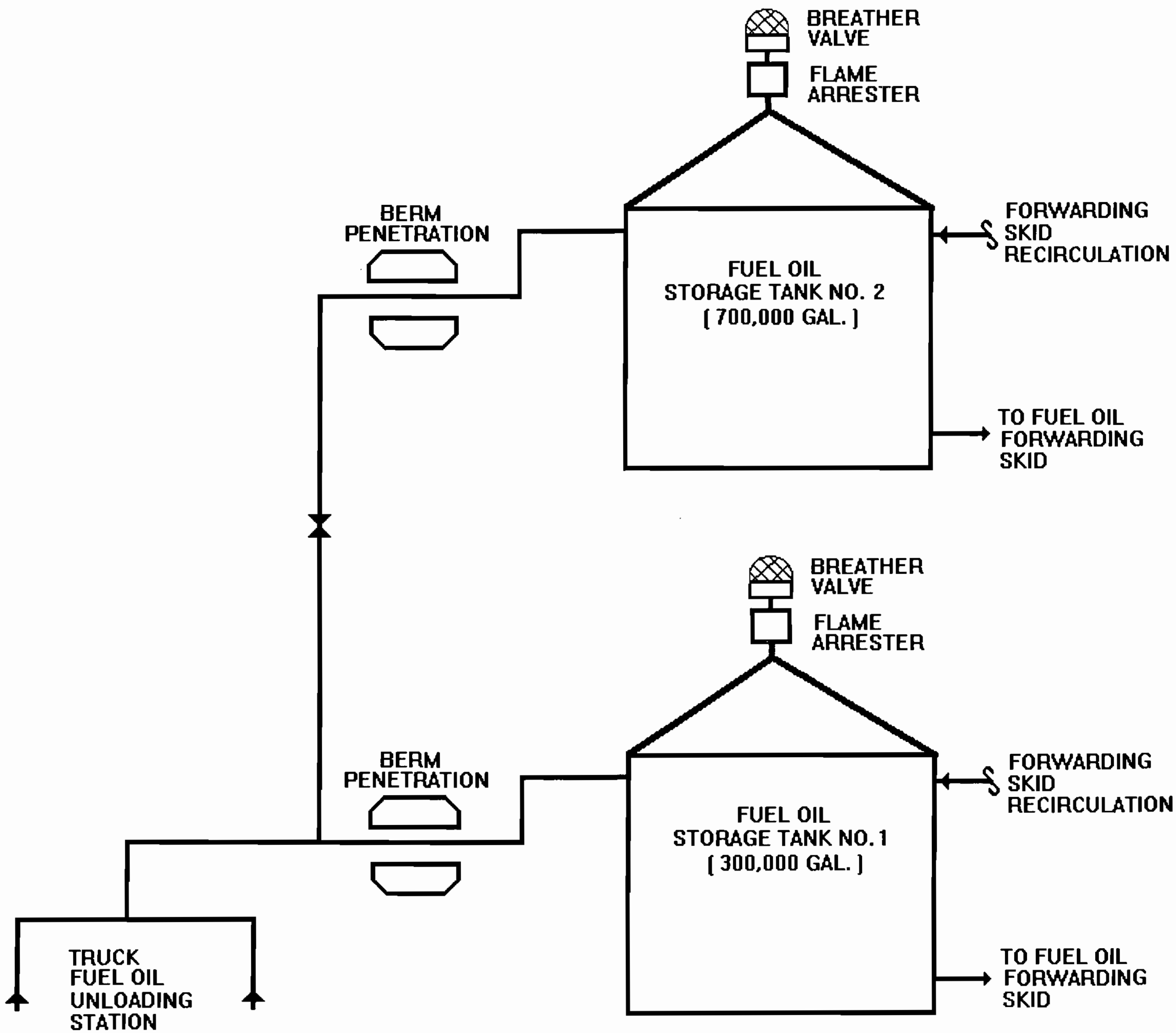
The CAM rule reproposal date (originally scheduled for December 1995) and the promulgation date of July 1, 1996, will likely be delayed from 7 to 9 months as a result of the Agency dealing with the significant issues raised in the comments on the draft rule and the recent government shutdown.

Compliance monitoring will be conducted as detailed in the Emissions Unit Information portion of this application, and as required by construction permit AC49-205703. If, after the approval and promulgation of the CAM rule, more restrictive compliance monitoring is required, the necessary steps will be undertaken to ensure the facility meets all monitoring requirements..

Appendix GG

Appendix GG

Process Flow Diagram


BREATHER
VALVE
FLAME
ARRESTER
BERM
PENETRATION
FUEL OIL
STORAGE TANK NO. 2
(700,000 GAL.)
FORWARDING
SKID
RECIRCULATION
TO FUEL OIL
FORWARDING
SKID
BREATHER
VALVE
FLAME
ARRESTER
BERM
PENETRATION
FUEL OIL
STORAGE TANK NO. 1
(300,000 GAL.)
FORWARDING
SKID
RECIRCULATION
TO FUEL OIL
FORWARDING
SKID
TRUCK
FUEL OIL
UNLOADING
STATION

Appendix HH

Appendix HH

Alternative Methods of Operation

Alternative Methods of Operation

The combustion turbine facility will burn natural gas as the primary fuel and No. 2 distillate fuel oil (0.05 percent sulfur) as a secondary back-up fuel. In the event of non-availability of natural gas (natural gas curtailment), the facility may burn No. 2 distillate fuel oil the entire year, or up to 1,000 hours per year if natural gas is available, with the remainder of the year on natural gas.

As provided for in the permit application instructions (Ref. DEP Form No. 62-210.900(1), page 20), the alternative methods of operation as the result of fuel options are discussed in detail in the Emissions Unit Information Section of the permit application.

Appendix II

Appendix II

Unit Specific Applicable Regulations

Unit Specific Applicable Regulations

Applicable Regulation	Applicable Requirement	Compliance Status	Compliance Method
40 CFR 60, Subpart Kb	**Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984.**	Comply	See details in applicable sections.
40 CFR 60.116b, Monitoring of operations	The owner or operator shall keep records according to the provisions of 40 CFR 60.116b (a) and (b)for a period of at least two (2) years.	Comply	As specified in this section.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.	Will comply when applicable	As specified in this section.
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130	Will comply when applicable	As specified in this section.
Permit Number: AC 49-205703	The facility will comply with all operating restrictions, performance testing, and emission limits incorporated in the referenced permit.	Comply	As specified in this section.

Appendix JJ

Appendix JJ

Process Flow Diagram

Process Flow Diagram

See Appendix GG for process flow diagram.

Appendix KK

Appendix KK

Alternative Methods of Operation

Alternative Methods of Operation

The combustion turbine facility will burn natural gas as the primary fuel and No. 2 distillate fuel oil (0.05 percent sulfur) as a secondary back-up fuel. In the event of non-availability of natural gas (natural gas curtailment), the facility may burn No. 2 distillate fuel oil the entire year, or up to 1,000 hours per year if natural gas is available, with the remainder of the year on natural gas.

As provided for in the permit application instructions (Ref. DEP Form No. 62-210.900(1), page 20), the alternative methods of operation as the result of fuel options are discussed in detail in the Emissions Unit Information Section of the permit application.

Appendix LL

Appendix LL

Unit Specific Applicable Regulations

Unit Specific Applicable Regulations

Applicable Regulation	Applicable Requirement	Compliance Status	Compliance Method
40 CFR 60, Subpart Kb	**Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984.**	Comply	See details in applicable sections.
40 CFR 60.116b, Monitoring of operations	The owner or operator shall keep records according to the provisions of 40 CFR 60.116b (a) and (b)for a period of at least two (2) years.	Comply	As specified in this section.
F.A.C. 62-210.650, Circumvention	No person shall circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly.	Will comply when applicable	As specified in this section.
F.A.C. 62-210.700, Excess Emissions	In case of excess emissions resulting from malfunctions, each owner or operator shall notify the DEP in accordance with F.A.C. 62-4.130	Will comply when applicable	As specified in this section.
Permit Number: AC 49-205703	The facility will comply with all operating restrictions, performance testing, and emission limits incorporated in the referenced permit.	Comply	As specified in this section.

Appendix MM

Appendix MM

Emission Source Calculations

TANKS PROGRAM 2.0
EMISSIONS REPORT - DETAIL FORMAT
TANK IDENTIFICATION AND PHYSICAL CHARACTERISTICS

Identification

Identification No.:	Tank #1
City:	Cane Island
State:	FL
Company:	KUA
Type of Tank:	Vertical Fixed Roof

Tank Dimensions

Shell Height (ft):	32
Diameter (ft):	40
Liquid Height (ft):	32
Avg. Liquid Height (ft):	32
Volume (gallons):	300000
Turnovers:	83
Net Throughput (gal/yr):	24900000

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Dome
Height (ft):	8.00
Radius (ft) (Dome Roof):	28.00
Slope (ft/ft) (Cone Roof):	0.0000

Breather Vent Settings

Vacuum Setting (psig):	-0.03
Pressure Setting (psig):	0.03

Meteorological Data Used in Emission Calculations: Orlando, Florida

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	74.41	68.90	79.92	72.42	0.0103	0.0087	0.0122	130.000			130.00	Option 4: A=12.1010, B=8907.0

Annual Emission Calculations

Standing Losses (lb):	17.7979
Vapor Space Volume (cu ft):	5591.23
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.037443
Vented Vapor Saturation Factor:	0.997579
Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	5591.23
Tank Diameter (ft):	40
Vapor Space Outage (ft):	4.45
Tank Shell Height (ft):	32
Average Liquid Height (ft):	32
Roof Outage (ft):	4.45
Roof Outage (Dome Roof)	
Roof Outage (ft):	4.45
Dome Radius (ft):	28
Shell Radius (ft):	20
Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010293
Daily Avg. Liquid Surface Temp.(deg. R):	534.08
Daily Average Ambient Temp. (deg. R):	532.07
Ideal Gas Constant R (psia cuft /(lb-mole-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	532.09
Tank Paint Solar Absorptance (Shell):	0.17
Tank Paint Solar Absorptance (Roof):	0.17
Daily Total Solar Insolation Factor (Btu/sqft*day):	1487.00
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.037443
Daily Vapor Temperature Range (deg.R):	22.05
Daily Vapor Pressure Range (psia):	0.003554
Breather Vent Press. Setting Range(psia):	0.06
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010293
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.008651
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.012204
Daily Avg. Liquid Surface Temp. (deg R):	534.08
Daily Min. Liquid Surface Temp. (deg R):	528.57
Daily Max. Liquid Surface Temp. (deg R):	539.59
Daily Ambient Temp. Range (deg.R):	20.80

$$(.012204 \text{ psia})\left(\frac{100 \text{ Pa}}{1.4504 \times 10^{-2} \text{ psi}}\right)\left(\frac{\text{kPa}}{1000 \text{ pa}}\right) = .084 \text{ kPa}$$

Annual Emission Calculations	
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.997579
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010293
Vapor Space Outage (ft):	4.45
Withdrawal Losses (lb):	419.7593
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010293
Annual Net Throughput (gal/yr):	24900000
Turnover Factor:	0.5291
Maximum Liquid Volume (cuft):	40212
Maximum Liquid Height (ft):	32
Tank Diameter (ft):	40
Working Loss Product Factor:	1.00
Total Losses (lb):	437.56

TANKS PROGRAM 2.0
EMISSIONS REPORT - DETAIL FORMAT
INDIVIDUAL TANK EMISSION TOTALS

Annual Emissions Report

Liquid Contents	Losses (lbs.): Standing	Withdrawal	Total
Distillate fuel oil no. 2	17.80	419.76	437.56
Total:	17.80	419.76	437.56

= .22 tpy

TANKS PROGRAM 2.0
EMISSIONS REPORT - DETAIL FORMAT
TANK IDENTIFICATION AND PHYSICAL CHARACTERISTICS

Identification	
Identification No.:	Tank #2
City:	Cane Island
State:	FL
Company:	KUA
Type of Tank:	Vertical Fixed Roof
Tank Dimensions	
Shell Height (ft):	33
Diameter (ft):	60
Liquid Height (ft):	33
Avg. Liquid Height (ft):	33
Volume (gallons):	700000
Turnovers:	83
Net Throughput (gal/yr):	58100000
Paint Characteristics	
Shell Color/Shade:	White/White
Shell Condition:	Good
Roof Color/Shade:	White/White
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft):	12.00
Radius (ft) (Dome Roof):	44.00
Slope (ft/ft) (Cone Roof):	0.0000
Breather Vent Settings	
Vacuum Setting (psig):	-0.03
Pressure Setting (psig):	0.03

Meteorological Data Used in Emission Calculations: Orlando, Florida

Mixture/Component	Month	Daily Liquid Surf. Temperatures (deg F) Avg.	Min.	Max.	Liquid Bulk Temp. (deg F)	Vapor Pressures (psia) Avg.	Min.	Max.	Vapor Mol. Weight	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	74.41	68.90	79.92	72.42	0.0103	0.0087	0.0122	130.000			130.00	Option 4: A=12.1010, B=8907.0

Annual Emission Calculations

Standing Losses (lb):	55.8539
Vapor Space Volume (cu ft):	17563.45
Vapor Density (lb/cu ft):	0.0002
Vapor Space Expansion Factor:	0.037443
Vented Vapor Saturation Factor:	0.996623

Tank Vapor Space Volume	
Vapor Space Volume (cu ft):	17563.45
Tank Diameter (ft):	60
Vapor Space Outage (ft):	6.21
Tank Shell Height (ft):	33
Average Liquid Height (ft):	33
Roof Outage (ft):	6.21

Roof Outage (Dome Roof)	
Roof Outage (ft):	6.21
Dome Radius (ft):	44
Shell Radius (ft):	30

Vapor Density	
Vapor Density (lb/cu ft):	0.0002
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010293
Daily Avg. Liquid Surface Temp.(deg. R):	534.08
Daily Average Ambient Temp. (deg. R):	532.07
Ideal Gas Constant R (psia cuft /(lb-mole-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	532.09
Tank Paint Solar Absorptance (Shell):	0.17
Tank Paint Solar Absorptance (Roof):	0.17
Daily Total Solar Insolation Factor (Btu/sqft*day):	1487.00

Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.037443
Daily Vapor Temperature Range (deg.R):	22.05
Daily Vapor Pressure Range (psia):	0.003554
Breather Vent Press. Setting Range(psia):	0.06
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010293
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.008651
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.012204
Daily Avg. Liquid Surface Temp. (deg R):	534.08
Daily Min. Liquid Surface Temp. (deg R):	528.57
Daily Max. Liquid Surface Temp. (deg R):	539.59
Daily Ambient Temp. Range (deg.R):	20.80

Annual Emission Calculations	
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.996623
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010293
Vapor Space Outage (ft):	6.21
Withdrawal Losses (lb):	975.6943
Vapor Molecular Weight (lb/lb-mole):	130.000000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.010293
Annual Net Throughput (gal/yr):	58100000
Turnover Factor:	0.5271
Maximum Liquid Volume (cuft):	93305
Maximum Liquid Height (ft):	33
Tank Diameter (ft):	60
Working Loss Product Factor:	1.00
Total Losses (lb):	1031.55

Annual Emissions Report

Liquid Contents	Losses (lbs.): Standing	Withdrawal	Total
Distillate fuel oil no. 2	55.85	975.69	1031.55
Total:	55.85	975.69	1031.55

= .52 tpy

BLACK & VEATCH ENGINEERS-ARCHITECTS	Owner	Computed By	TM Hillman
	Plant / Unit	Date	7/7 1995
	Project No. / File No.	Checked By	J.G. Tongeman
	Title	Date	7/7 1995
		Page / of	

Purpose: Determine unconfined particulate matter emissions associated with worker and delivery vehicles at the site.

Ref: US. EPA AP-42, Chapt 11.2.6, Industrial Paved Roads.

AP-42 Emission Factor Equation

All roads at the site are paved, therefore; use emission factor equation for industrial paved roads.

$$E\,(\text{lb/VMT}) = 0.077(I)\left(\frac{4}{n}\right)\left(\frac{s}{10}\right)\left(\frac{L}{1000}\right)\left(\frac{W}{3}\right)^{0.7}$$

I: industrial augmentation factor 1.0

n: number of traffic lanes 2

s: silt content 12% (AP-42 Table 11.2.6-1)

L: dust loading 1.75 lb/mile "

W: average vehicle wt. in tons

$$E = 0.077(1.0)\left(\frac{4}{2}\right)\left(\frac{12}{10}\right)\left(\frac{1.75}{1000}\right)\left(\frac{W}{3}\right)^{0.7} = .00032\left(\frac{W}{3}\right)^{0.7}\ \text{lb/VMT}$$

Worker Vehicle Movement

Assumptions:

- 20 worker and site vehicles on site with an average weight of 2 tons
- all vehicles make an round trip of the facility (0.6 miles) per day

$$\left(\frac{.00032\left(\frac{2}{3}\right)^{.7}\ \text{lb}}{\text{VMT}}\right)\left(\frac{20\ \text{vehicles}}{\text{day}}\right)\left(\frac{0.6\ \text{miles}}{\text{trip}}\right)\left(\frac{365\ \text{days}}{\text{yr}}\right)\left(\frac{\text{ton}}{2000\ \text{lbs}}\right) = 0.00053\ \text{tpy}$$

DO NOT WRITE IN THIS SPACE

P-GN-172A

BLACK & VEATCH ENGINEERS-ARCHITECTS

Owner		Computed By	TM Hillm.
Plant	Unit	Date	7/7 1995
Project No.	File No.	Checked By	J. G. Tangeman
Title		Date	7/2 1995
		Page	of

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Delivery Vehicles

Assumptions:

- 7 deliveries per week of mail, consumables, etc., with an average weight of 5 tons

$$\left(\frac{.00032\left(\frac{5}{3}\right)^{0.7}\text{lb}}{\text{VMT}}\right)\left(\frac{7\text{ vehicles}}{\text{week}}\right)\left(\frac{0.6\text{ miles}}{\text{trip}}\right)\left(\frac{52\text{ weeks}}{\text{yr}}\right)\left(\frac{\text{ton}}{2000\text{ lbs}}\right) = 0.00005\text{ tpy}$$

Trash Pick-up

Assumptions

- 2 trash pickups per week, with an average weight of 10 tons

$$\left(\frac{.00032\left(\frac{10}{3}\right)^{0.7}\text{lb}}{\text{VMT}}\right)\left(\frac{2\text{ vehicles}}{\text{week}}\right)\left(\frac{0.6\text{ miles}}{\text{trip}}\right)\left(\frac{52\text{ weeks}}{\text{yr}}\right)\left(\frac{\text{ton}}{2000\text{ lbs}}\right) = 0.00002\text{ tpy}$$

Fuel oil delivery

Assumptions

- fuel oil delivery based on firing both units on fuel oil for the entire year

$$\left(\underbrace{\frac{371\text{ mmBtu}}{\text{h}}}_{\text{Heat input Unit 1}} + \underbrace{\frac{928\text{ mmBtu}}{\text{h}}}_{\text{Heat input Unit 2}}\right)\left(\frac{1000\text{ gal}}{137\text{ mmBtu}}\right)\left(\frac{8760\text{ h}}{\text{yr}}\right) \cong 83{,}000{,}000\text{ gal/yr}$$

- assume delivery trucks hold 7,500 gallons, with an average weight of 20 tons

$$\left(\frac{.00032\left(\frac{20}{3}\right)^{0.7}\text{lb}}{\text{VMT}}\right)\left(\frac{83{,}000{,}000\text{ gal}}{\text{yr}}\right)\left(\frac{\text{truck}}{7{,}500\text{ gal}}\right)\left(\frac{0.6\text{ miles}}{\text{trip}}\right)\left(\frac{\text{ton}}{2000\text{ lbs}}\right) = 0.004\text{ tpy}$$

Total unconfined particulate matter emissions = .005 tpy

BLACK & VEATCH ENGINEERS-ARCHITECTS		
Owner		Computed By Tm Hillman
Plant	Unit	Date 7/10 1995
Project No.	File No.	Checked By
Title		Date 19
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Purpose: estimate Hydrazine emissions from the boiler Feed water system hydrazine storage tank vent.

Based on the facility's chemical usage inventory, approximately one-half gallon of hydrazine is used every 4 days. The hydrazine is actually a 15% (maximum) solution of hydrazine and water. For conservatism, it is assumed the storage tank contains 100% hydrazine and that 10% evaporates and is vented through the storage tank vent when the tank is filled

Accordingly, hydrazine emissions may be estimated as follows:

$$\left(\frac{0.5 \text{ gals Hydrazine}}{4 \text{ days}}\right)\left(\frac{365 \text{ days}}{\text{year}}\right)\left(\frac{1.019 \text{ Hydrazine}}{1.0 \ H_2O}\right)\left(\frac{62.43 \text{ lbs}}{ft^3}\right)\left(\frac{ft^3}{7.48 \text{ gals}}\right)\left(\frac{\text{ton}}{2000 \text{ lbs}}\right)\left(\frac{10\% \text{ evap}}{100}\right) = 0.02 \text{ tpy}$$

P-GN-172A

BLACK & VEATCH
ENGINEERS-ARCHITECTS

Owner ______ Computed By ______
Plant ______ Unit ______ Date ______ 19 ___
Project No. ______ File No. ______ Checked By ______
Title ______ Date ______ 19 ___
Page ______ of ______

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Purpose: Estimate VOC and hexane emissions from fuel purging vents and Natural gas line and processing vents.

From the natural gas fuel analyses presented in Appendix N, the natural gas is approximately 95% methane. Because VOCs do not include methane, the remaining 5% will conservatively be assumed to be VOCs. The fuel analysis also indicates that the natural gas contains less than 0.02% Hexane. For the purposes of this calculation, hexane will be assumed to be 0.02%.

It is estimated that approximately 100 lbs of natural gas is vented in processing vents and fuel purge points during startup and shut down evolutions for each combustion turbine.

Accordingly, VOC and hydrazine emissions may be estimated as follows.

VOC

$$\left(\frac{100 \text{ lbs of Natural gas}}{\text{Unit - Startup/Shutdown}}\right)\left(\frac{730 \text{ Startup/shutdown}}{\text{Unit}}\right)\left(2 \text{ units}\right)\left(\frac{5\% \text{ VOC}}{100}\right)\left(\frac{\text{ton}}{2000 \text{ lbs}}\right) = 3.65 \text{ tpy}$$

Hexane

$$\left(\frac{100 \text{ lbs of Natural gas}}{\text{Unit - Startup/Shutdown}}\right)\left(\frac{730 \text{ Startup/shutdown}}{\text{Unit}}\right)\left(2 \text{ units}\right)\left(\frac{.02\% \text{ Hexane}}{100}\right)\left(\frac{\text{ton}}{2000 \text{ lbs}}\right) = 0.015 \text{ tpy}$$

P-GN-172A

KUA - Cane Island Power Park

HAPS Calculations

Scenario Assumptions: Natural gas firing for the entire year.

Emission Source ID Number														PTE (tpy)
S-1	40 MW Simple Cylce Combustion Turbine (Distillate Oil)			371 MBtu/h		0 h/yr								
	SCC_CODE	SCC_NAME	SCC_NAME	SCC_NAME	SCC_NAME	SIC_CODE	SIC_NAME	POL_NAME	HAPS?	FACTOR	FACTOR	EF_UNITS	EF_UNITS_X	
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Antimony	yes	2.20000E-5	2.2000E-05	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Arsenic	yes	4.90000E-6	4.9000E-06	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine	4911	Electric Services	Benzene	yes	9.13000E-5	9.1300E-05	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Beryllium	yes	3.30000E-7	3.3000E-07	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Cadmium	yes	4.20000E-6	4.2000E-06	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Chromium	yes	4.70000E-5	4.7000E-05	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Cobalt	yes	9.10000E-6	9.1000E-06	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine	4911	Electric Services	Formaldehyde	yes	1.01000E-3	1.0100E-03	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Lead	yes	5.80000E-5	5.8000E-05	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Manganese	yes	3.40000E-4	3.4000E-04	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Mercury	yes	9.10000E-7	9.1000E-07	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Phosphorus (yellow or white)	yes	3.00000E-4	3.0000E-04	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Selenium	yes	5.30000E-6	5.3000E-06	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Nickel	yes	1.20000E-3	1.2000E-03	lb/MMBtu	heat input	0.000
S-1	40 MW Simple Cylce Combustion Turbine (Natural Gas)			367 MBtu/h		8760 h/yr								
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Benzene	yes	1.10000E-4	1.1000E-04	lb/MMBtu	heat input	0.177
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine	4911	Electric Services	Formaldehyde	yes	2.70000E-3	2.7000E-03	lb/MMBtu	fuel input	4.340
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Toluene	yes	< 2.30000E-5	2.3000E-05	lb/MMBtu	heat input	0.037
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Xylenes (mixed isomers)	yes	< 4.00000E-5	4.0000E-05	lb/MMBtu	heat input	0.064
S-2 or S-3	120 MW Combined Cylce Combustion Turbine (Distillate Oil)			928 MBtu/h		0 h/yr								
	SCC_CODE	SCC_NAME	SCC_NAME	SCC_NAME	SCC_NAME	SIC_CODE	SIC_NAME	POL_NAME	HAPS?	FACTOR	FACTOR	EF_UNITS	EF_UNITS_X	
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Antimony	yes	2.20000E-5	2.2000E-05	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Arsenic	yes	4.90000E-6	4.9000E-06	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine	4911	Electric Services	Benzene	yes	9.13000E-5	9.1300E-05	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Beryllium	yes	3.30000E-7	3.3000E-07	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Cadmium	yes	4.20000E-6	4.2000E-06	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Chromium	yes	4.70000E-5	4.7000E-05	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Cobalt	yes	9.10000E-6	9.1000E-06	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine	4911	Electric Services	Formaldehyde	yes	1.01000E-3	1.0100E-03	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Lead	yes	5.80000E-5	5.8000E-05	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Manganese	yes	3.40000E-4	3.4000E-04	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Mercury	yes	9.10000E-7	9.1000E-07	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Phosphorus (yellow or white)	yes	3.00000E-4	3.0000E-04	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Selenium	yes	5.30000E-6	5.3000E-06	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Nickel	yes	1.20000E-3	1.2000E-03	lb/MMBtu	heat input	0.000
S-2 or S-3	120 MW Combined Cylce Combustion Turbine (Natural Gas)			869 MBtu/h		8760 h/yr								
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Benzene	yes	1.10000E-4	1.1000E-04	lb/MMBtu	heat input	0.419
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine	4911	Electric Services	Formaldehyde	yes	2.70000E-3	2.7000E-03	lb/MMBtu	fuel input	10.277
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Toluene	yes	< 2.30000E-5	2.3000E-05	lb/MMBtu	heat input	0.088
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Xylenes (mixed isomers)	yes	< 4.00000E-5	4.0000E-05	lb/MMBtu	heat input	0.152
S-4	#1 Distillate Fuel Oil Storage Tank (300,000 gal)													
	40301020	Assuming all VOC emissions calculated via TANKS are HAPS (See Appendix FF for TANKS program output)												0.220
S-5	#2 Distillate Fuel Oil Storage Tank (700,000 gal)													
	40301020	Assuming all VOC emissions calculated via TANKS are HAPS (See Appendix FF for TANKS program output)												0.520
S-82	Hydrazine Storage Tank Vent							Hydrazine	yes					0.020
		See Appendix FF for calculation sheet												
S-88 to S-93 & S-102, S-103 & S-106 to S-108	Natural gas fuel purge vents and natural gas line/processing vents							Hexane	yes					0.015
		See Appendix FF for calculation sheet												
S-94 to S-101	Oil/Water seperator waste water collection tank vents													0.740
		Assuming all VOC emissions calculated via TANKS are HAPS. Additionally, it is conservatively assumed that these waste water collection tank vents would have the same emissions as the fuel oil storage tanks (i.e., S-4 and S-5)												
		See Appendix FF for calculation sheet												
													Total HAPS	17.069 tpy

KUA - Cane Island Power Park

HAPS Calculations

Scenario Assumptions: Distillate fuel oil firing for 1,000 hours per year, with the remainder of the year natural gas firing

Emission Source ID Number														PTE (tpy)
S-1	40 MW Simple Cyice Combustion Turbine (Distillate Oil)			371	MBtu/h	1000	hr/yr							
	SCC_CODE	SCC_NAME	SCC_NAME	SCC_NAME	SCC_NAME	SIC_CODE	SIC_NAME	POL_NAME	HAPS?	FACTOR	FACTOR	EF_UNITS	EF_UNITS_X	
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Antimony	yes	2.20000E-5	2.2000E-05	lb/MMBtu	heat input	0.004
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Arsenic	yes	4.90000E-6	4.9000E-06	lb/MMBtu	heat input	0.001
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine	4911	Electric Services	Benzene	yes	9.13000E-5	9.1300E-05	lb/MMBtu	heat input	0.017
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Beryllium	yes	3.30000E-7	3.3000E-07	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Cadmium	yes	4.20000E-6	4.2000E-06	lb/MMBtu	heat input	0.001
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Chromium	yes	4.70000E-5	4.7000E-05	lb/MMBtu	heat input	0.009
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Cobalt	yes	9.10000E-6	9.1000E-06	lb/MMBtu	heat input	0.002
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine	4911	Electric Services	Formaldehyde	yes	1.01000E-3	1.0100E-03	lb/MMBtu	heat input	0.187
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Lead	yes	5.80000E-5	5.8000E-05	lb/MMBtu	heat input	0.011
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Manganese	yes	3.40000E-4	3.4000E-04	lb/MMBtu	heat input	0.063
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Mercury	yes	9.10000E-7	9.1000E-07	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Phosphorus (yellow or white)	yes	3.00000E-4	3.0000E-04	lb/MMBtu	heat input	0.056
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Selenium	yes	5.30000E-6	5.3000E-06	lb/MMBtu	heat input	0.001
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Nickel	yes	1.20000E-3	1.2000E-03	lb/MMBtu	heat input	0.223
S-1	40 MW Simple Cyice Combustion Turbine (Natural Gas)			367	MBtu/h	7760	hr/yr							
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Benzene	yes	1.10000E-4	1.1000E-04	lb/MMBtu	heat input	0.157
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine	4911	Electric Services	Formaldehyde	yes	2.70000E-3	2.7000E-03	lb/MMBtu	fuel input	3.845
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Toluene	yes	< 2.30000E-5	2.3000E-05	lb/MMBtu	heat input	0.033
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Xylenes (mixed isomers)	yes	< 4.00000E-5	4.0000E-05	lb/MMBtu	heat input	0.057
S-2 or S-3	120 MW Combined Cyice Combustion Turbine (Distillate Oil)			928	MBtu/h	1000	hr/yr							
	SCC_CODE	SCC_NAME	SCC_NAME	SCC_NAME	SCC_NAME	SIC_CODE	SIC_NAME	POL_NAME	HAPS?	FACTOR	FACTOR	EF_UNITS	EF_UNITS_X	
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Antimony	yes	2.20000E-5	2.2000E-05	lb/MMBtu	heat input	0.010
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Arsenic	yes	4.90000E-6	4.9000E-06	lb/MMBtu	heat input	0.002
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine	4911	Electric Services	Benzene	yes	9.13000E-5	9.1300E-05	lb/MMBtu	heat input	0.042
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Beryllium	yes	3.30000E-7	3.3000E-07	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Cadmium	yes	4.20000E-6	4.2000E-06	lb/MMBtu	heat input	0.002
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Chromium	yes	4.70000E-5	4.7000E-05	lb/MMBtu	heat input	0.022
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Cobalt	yes	9.10000E-6	9.1000E-06	lb/MMBtu	heat input	0.004
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine	4911	Electric Services	Formaldehyde	yes	1.01000E-3	1.0100E-03	lb/MMBtu	heat input	0.469
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Lead	yes	5.80000E-5	5.8000E-05	lb/MMBtu	heat input	0.027
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Manganese	yes	3.40000E-4	3.4000E-04	lb/MMBtu	heat input	0.158
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Mercury	yes	9.10000E-7	9.1000E-07	lb/MMBtu	heat input	0.000
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Phosphorus (yellow or white)	yes	3.00000E-4	3.0000E-04	lb/MMBtu	heat input	0.139
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Selenium	yes	5.30000E-6	5.3000E-06	lb/MMBtu	heat input	0.002
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Nickel	yes	1.20000E-3	1.2000E-03	lb/MMBtu	heat input	0.557
S-2 or S-3	120 MW Combined Cyice Combustion Turbine (Natural Gas)			869	MBtu/h	7760	hr/yr							
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Benzene	yes	1.10000E-4	1.1000E-04	lb/MMBtu	heat input	0.371
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine	4911	Electric Services	Formaldehyde	yes	2.70000E-3	2.7000E-03	lb/MMBtu	fuel input	9.104
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Toluene	yes	< 2.30000E-5	2.3000E-05	lb/MMBtu	heat input	0.078
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Xylenes (mixed isomers)	yes	< 4.00000E-5	4.0000E-05	lb/MMBtu	heat input	0.135
S-4	#1 Distillate Fuel Oil Storage Tank (300,000 gal)													
	40301020	Assuming all VOC emissions calculated via TANKS are HAPS (See Appendix FF for TANKS program output)												0.220
S-5	#2 Distillate Fuel Oil Storage Tank (700,000 gal)													
	40301020	Assuming all VOC emissions calculated via TANKS are HAPS (See Appendix FF for TANKS program output)												0.520
S-82	Hydrazine Storage Tank Vent							Hydrazine	yes					0.020
		See Appendix FF for calculation sheet												
S-88 to S-93 & S-102, S-103 & S-106 to S-108	Natural gas fuel purge vents and natural gas line/processing vents							Hexane	yes					0.015
		See Appendix FF for calculation sheet												
S-94 to S-101	Oil/Water separator waste water collection tank vents													0.740
		Assuming all VOC emissions calculated via TANKS are HAPS. Additionally, it is conservatively assumed that these waste water collection tank vents would have the same emissions as the fuel oil storage tanks (i.e., S-4 and S-5)												
		See Appendix FF for calculation sheet												
													Total HAPS	17.302 tpy

KUA - Cane Island Power Park

HAPS Calculations

Scenario Assumptions: Distillate fuel oil firing for the entire year

Emission Source ID Number	SCC_CODE	SCC_NAME	SCC_NAME	SCC_NAME	SCC_NAME	SIC_CODE	SIC_NAME	POL_NAME	HAPS?	FACTOR	FACTOR	EF_UNITS	EF_UNITS_X	PTE (tpy)
S-1	40 MW Simple Cycle Combustion Turbine (Distillate Oil)				371 MBtu/h	8760 h/yr								
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Antimony	yes	2.20000E-5	2.2000E-05	lb/MMBtu	heat input	0.036
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Arsenic	yes	4.90000E-6	4.9000E-06	lb/MMBtu	heat input	0.008
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine	4911	Electric Services	Benzene	yes	9.13000E-5	9.1300E-05	lb/MMBtu	heat input	0.148
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Beryllium	yes	3.30000E-7	3.3000E-07	lb/MMBtu	heat input	0.001
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Cadmium	yes	4.20000E-6	4.2000E-06	lb/MMBtu	heat input	0.007
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Chromium	yes	4.70000E-5	4.7000E-05	lb/MMBtu	heat input	0.076
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Cobalt	yes	9.10000E-6	9.1000E-06	lb/MMBtu	heat input	0.015
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine	4911	Electric Services	Formaldehyde	yes	1.01000E-3	1.0100E-03	lb/MMBtu	heat input	1.641
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Lead	yes	5.80000E-5	5.8000E-05	lb/MMBtu	heat input	0.094
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Manganese	yes	3.40000E-4	3.4000E-04	lb/MMBtu	heat input	0.552
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Mercury	yes	9.10000E-7	9.1000E-07	lb/MMBtu	heat input	0.001
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Phosphorus (yellow or white)	yes	3.00000E-4	3.0000E-04	lb/MMBtu	heat input	0.487
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Selenium	yes	5.30000E-6	5.3000E-06	lb/MMBtu	heat input	0.009
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Nickel	yes	1.20000E-3	1.2000E-03	lb/MMBtu	heat input	1.950
S-1	40 MW Simple Cycle Combustion Turbine (Natural Gas)				367 MBtu/h	0 h/yr								
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Benzene	yes	1.10000E-4	1.1000E-04	lb/MMBtu	heat input	0.000
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine	4911	Electric Services	Formaldehyde	yes	2.70000E-3	2.7000E-03	lb/MMBtu	fuel input	0.000
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Toluene	yes	< 2.30000E-5	2.3000E-05	lb/MMBtu	heat input	0.000
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Xylenes (mixed isomers)	yes	< 4.00000E-5	4.0000E-05	lb/MMBtu	heat input	0.000
S-2 or S-3	120 MW Combined Cylce Combustion Turbine (Distillate Oil)				928 MBtu/h	8760 h/yr								
	SCC_CODE	SCC_NAME	SCC_NAME	SCC_NAME	SCC_NAME	SIC_CODE	SIC_NAME	POL_NAME	HAPS?	FACTOR	FACTOR	EF_UNITS	EF_UNITS_X	
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Antimony	yes	2.20000E-5	2.2000E-05	lb/MMBtu	heat input	0.089
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Arsenic	yes	4.90000E-6	4.9000E-06	lb/MMBtu	heat input	0.020
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine	4911	Electric Services	Benzene	yes	9.13000E-5	9.1300E-05	lb/MMBtu	heat input	0.371
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Beryllium	yes	3.30000E-7	3.3000E-07	lb/MMBtu	heat input	0.001
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Cadmium	yes	4.20000E-6	4.2000E-06	lb/MMBtu	heat input	0.017
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Chromium	yes	4.70000E-5	4.7000E-05	lb/MMBtu	heat input	0.191
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Cobalt	yes	9.10000E-6	9.1000E-06	lb/MMBtu	heat input	0.037
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine	4911	Electric Services	Formaldehyde	yes	1.01000E-3	1.0100E-03	lb/MMBtu	heat input	4.105
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Lead	yes	5.80000E-5	5.8000E-05	lb/MMBtu	heat input	0.236
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Manganese	yes	3.40000E-4	3.4000E-04	lb/MMBtu	heat input	1.382
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Mercury	yes	9.10000E-7	9.1000E-07	lb/MMBtu	heat input	0.004
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Phosphorus (yellow or white)	yes	3.00000E-4	3.0000E-04	lb/MMBtu	heat input	1.219
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Selenium	yes	5.30000E-6	5.3000E-06	lb/MMBtu	heat input	0.022
	20100101	Internal Combustion Engines	Electric Generation	Distillate Oil/Diesel	Turbine			Nickel	yes	1.20000E-3	1.2000E-03	lb/MMBtu	heat input	4.878
S-2 or S-3	120 MW Combined Cylce Combustion Turbine (Natural Gas)				869 MBtu/h	0 h/yr								
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Benzene	yes	1.10000E-4	1.1000E-04	lb/MMBtu	heat input	0.000
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine	4911	Electric Services	Formaldehyde	yes	2.70000E-3	2.7000E-03	lb/MMBtu	fuel input	0.000
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Toluene	yes	< 2.30000E-5	2.3000E-05	lb/MMBtu	heat input	0.000
	20100201	Internal Combustion Engines	Electric Generation	Natural Gas	Turbine			Xylenes (mixed isomers)	yes	< 4.00000E-5	4.0000E-05	lb/MMBtu	heat input	0.000
S-4	#1 Distillate Fuel Oil Storage Tank (300,000 gal)													
	40301020	Assuming all VOC emissions calculated via TANKS are HAPS (See Appendix FF for TANKS program output)												0.220
S-5	#2 Distillate Fuel Oil Storage Tank (700,000 gal)													
	40301020	Assuming all VOC emissions calculated via TANKS are HAPS (See Appendix FF for TANKS program output)												0.520
S-82	Hydrazine Storage Tank Vent							Hydrazine	yes					0.020
		See Appendix FF for calculation sheet												
S-88 to S-93 & S-102, S-103 & S-106 to S-108	Natural gas fuel purge vents and natural gas line/processing vents							Hexene	yes					0.015
		See Appendix FF for calculation sheet												
S-94 to S-101	Oil/Water separator waste water collection tank vents													0.740
		Assuming all VOC emissions calculated via TANKS are HAPS. Additionally, it is conservatively assumed that these waste water collection tank vents would have the same emissions as the fuel oil storage tanks (i.e., S-4 and S-5)												
		See Appendix FF for calculation sheet												
													Total HAPS	19.113 tpy

Appendix NN

Appendix NN

Construction Permit AC49-205703

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
NOTICE OF PERMIT

In the matter of an
Application for Permit by:

DER File No. AC49-205703
PSD-FL-182

Mr. A. K. Sharmer
Director of Power Supply
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741

Enclosed is Permit Number AC49-205703 to construct a 40 MW simple cycle combustion turbine (SCCT) and a 120 MW combined cycle combustion turbine (CCCT). The combustion turbines will have the capability to fire either natural gas or No. 2 fuel oil. Water injection or low NOx combustors will be used to control nitrogen oxides (NOx) emissions and low sulfur fuel (0.5% S) will be fired to control sulfur dioxide (SO_2) emissions. The CCCT will intermittenly operate in a simple cycle when the HRSG or steam turbine is down for maintenance and/or repair. These two combustion gas turbines are located in Kissimmee, Osceola County, Florida.

Any party to this Order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

RECEIVED
APR 12 1993
ELSS

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on 4-9-93 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

(Clerk) 4-9-93 (Date)

Copies furnished to:

Mr. T. A. Kaczmarski, P.E.
Mr. Chuck Collins, CD
Ms. Jewell Harper, EPA
Mr. John Bunyak, NPS

Final Determination

Kissimmee Utility Authority
Kissimmee, Osceola County, Florida

40 MW Simple Cycle Combustion Gas Turbine
120 MW Combined Cycle Combustion Gas Turbine

Permit Number: AC49-205703
PSD-FL-182

Department of Environmental Regulation
Division of Air Resources Management
Bureau of Air Regulation

April 1, 1993

FINAL DETERMINATION

The Technical Evaluation and Preliminary Determination for the permit to construct a 40 MW simple cycle combustion turbine (SCCT) and a 120 MW combined cycle combustion turbine (CCCT) system facility in Intercession City, Florida, was distributed on November 18, 1992. The Notice of Intent was published in The Orlando Sentinel on December 20, 1992. Copies of the evaluation were available for inspection at the Department's offices in Orlando and Tallahassee.

Kissimmee Utility Authority's (KUA) application for a permit to construct a 40 MW SCCT and a 120 MW CCCT system facility at their Intercession City site has been reviewed by the Bureau of Air Regulation in Tallahassee.

No adverse comments were submitted by the U.S. Environmental Protection Agency (EPA) in their letter dated December 17, 1992, or by the U.S. Department of the Interior in their letters of December 18, 1992, and January 26, 1993.

Comments regarding the Technical Evaluation and Preliminary Determination (Sypnosis of Application) and specific conditions of the permit were submitted by Donald D. Shultz of Black & Veatch. The Bureau has considered Mr. Shultz's comments and has agreed to the changes proposed in the material covered by the document entitled "Synopsis of Application" (page 2 through 9) as requested. Regarding the modification of the specific conditions of the permit, these changes, if accepted, will be finalized as follows:

DER PERMIT NUMBER AC49-205703, PSD-FL-182, FOR THE KUA 120 MW COMBINED CYCLE TURBINE AND 40 MW SIMPLE CYCLE TURBINE

RESPONSE TO COMMENT No. 1

The expiration date will be changed to **March 31, 1995**

RESPONSE TO COMMENT No. 2, 3, and 4

Specific Condition No. 8

Compliance with the NO_x, SO_2, CO, PM, PM_{10}, and VOC standards shall be determined (while operating at 95-100% of the permitted maximum heat input rate **corresponding to the particular ambient conditions**) within 180 days of initial operation of the maximum capability of the unit and annually thereafter, by the following reference methods as described in 40 CFR 60, Appendix A (July 1992 version) and adopted by reference in F.A.C. Rule 17-297.

- Method 1 Sample and Velocity Traverses
- Method 2 Volumetric Flow Rate
- Method 3 Gas Analysis

-	Method 5 or Method 17	Determination of Particulate Emissions from Stationary Sources
-	Method 9	Visual Determination of the Opacity of Emissions from Stationary Sources
-	Method 8	Determination of Sulfuric Acid Mist and **Sulfur Dioxide Emissions** from Stationary Sources (**for fuel oil burning only**).
-	Method 10	Determination of Carbon Monoxide **Emissions** from Stationary Sources
-	Method 20	Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines
-	Method 25A	Determination of Total Gaseous Organic Concentrations Using a Flame Ionization Analyzer

Other DER approved methods may be used for compliance testing after prior Departmental approval.

RESPONSE TO COMMENT No. 5

This condition will not be deleted. The Department is declining this request because natural gas contains varying small amounts of sulfur. Recent applications for similar turbines burning natural gas have shown emissions up to 4 lbs SO_2/hr. If SO_2 emissions from any of these sources exceed 40 TPY, the project will be retroactively subject to the PSD regulations for this pollutant.

RESPONSE TO COMMENT No. 6

Conditions Nos. 16, 17 and 18 will be combined and reworded as follows:

Specific Condition No. 16

The permittee shall comply with the following requirements:

(a) Install, calibrate, maintain, and operate a continuous emission monitor in each stack to measure and record the nitrogen oxides emissions from each source. The continuous emission monitor must comply with 40 CFR 60, Appendix B, Performance Specification 2 (July 1, 1992); (b) A continuous monitoring system shall be installed to monitor and record the fuel consumption on each unit. While water injection is being utilized for NO_X control, the water to fuel ratio at which compliance is achieved shall be incorporated into the permit and shall be continuously monitored. The system shall meet the requirements of 40 CFR Part 60, Subpart GG; (c) In addition, literature on equipment selected shall be submitted as it becomes available. A CT-specific graph of the relationship between

NOx emissions and water injection and also another of ambient temperature and heat inputs to the CT shall be submitted to DER's Central District office and the Bureau of Air Regulation.

RESPONSE TO COMMENTS ON TABLES 1 and 2, and BACT DETERMINATION

The numerical levels for CO, PM and Be were modified as requested. The BACT emission level for NO_x will remain as originally set for both turbines (15 ppmvd). However, the wording of some sections of the BACT determination was modified as requested by the applicant.

Because of the uncertainty of time of the NO_x control technology being achieved for the simple cycle CT, the Department will review this permit annually (after 1/1/95) and will modify its specific conditions to reflect the BACT Determination NO_x emission level, if appropiate.

In response to comments from the Department of the Interior (Fish and Wildlife Services) Specific Condition No. 15 will be changed as follows:

Specific Condition No. 15

The permittee shall comply with the following by 1/1/98:

a) For the combined cycle unit (PG7111EA), if the 15 (gas)/42 (oil) ppmv emission rates cannot be met by 1/1/98, SCR will be installed. Hence, the permittee shall install a duct module suitable for future installation of SCR equipment.
b) For the simple cycle unit (LM6000), the manufacturer will attempt to achieve a maximum NO_x emission level of 15 (gas)/42 (oil) ppmv by 1/1/98. Should this level of control not be achieved when the compliance demonstration stack tests are performed, the permittee must provide the Department with expected compliance dates which will be updated annually. After 1/1/98, if the compliance schedule has not been met, the Department may require SCR be installed since the exhaust temperature has an acceptable range for SCR installation.

The Department will revise permitted emission levels for NO_x for both turbines if the manufacturer achieves an even lower NO_x emission than 15 (gas)/42 (oil) ppmv pursuant to F.A.C. Rule 17-4.080, Modification of Permit Conditions.

The final action of the Department will be to issue construction permit AC49-205703 (PSD-FL-182) with the changes noted above.

BEST AVAILABLE COPY

Florida Department of Environmental Regulatio[n]

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-240[0]

Lawton Chiles, Governor

Virginia B. Wetherell, Secreta[ry]

PERMITTEE:
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741

Permit Number: AC49-205703
PSD-FL-182
Expiration Date: March 31, 1995
County: Osceola
Latitude/Longitude: 28°16'40"N
81°30'42"W
Project: A 120 MW Combined Cycle Turbine and a 40 MW Simple Cycle Turbine

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-209 through 17-297. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

Kissimmee Utility Authority proposes to operate a 40 MW simple cycle combustion turbine (SCCT) and a 120 MW combined cycle combustion turbine (CCCT) consisting of one combustion turbine, one steam turbine, one heat recovery steam generator and ancillary equipment. This facility is located near Intercession City, Osceola County, Florida. The UTM coordinates are Zone 17, 447.722 km East and 3127.685 km North.

The sources shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:

1. Kissimmee Utility Authority (KUA) applications received on November 15, 1991, and June 2, 1992.
2. Department's letter dated June 30, 1992.
3. KUA's letter received on July 30, 1992.
4. KUA's letters received on August 17 and October 8, 1992.

GENERAL CONDITIONS:

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

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

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

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

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

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

PERMITTEE:
Kissimmee Utility Authority

Permit Number: AC 49-205703
PSD-FL-182
Expiration Date: March 31, 1995

GENERAL CONDITIONS:

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

a. Have access to and copy any records that must be kept under the conditions of the permit;

b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and

c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

a. a description of and cause of non-compliance; and

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

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

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

GENERAL CONDITIONS:

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

11. This permit is transferable only upon Department approval i accordance with Florida Administrative Code Rules 17-4.120 an 17-30.300, F.A.C., as applicable. The permittee shall be liable fo any non-compliance of the permitted activity until the transfer i approved by the Department.

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

13. This permit also constitutes:

- (x) Determination of Best Available Control Technology (BACT)
- (x) Determination of Prevention of Significant Deterioration (PSD)
- (x) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

a. Upon request, the permittee shall furnish all records an plans required under Department rules. During enforcemen actions, the retention period for all records will b extended automatically unless otherwise stipulated by th Department.

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

c. Records of monitoring information shall include:

- the date, exact place, and time of sampling o measurements;

GENERAL CONDITIONS:

- the person responsible for performing the sampling or measurements;
- the dates analyses were performed;
- the person responsible for performing the analyses;
- the analytical techniques or methods used; and
- the results of such analyses.

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

SPECIFIC CONDITIONS:

Emission Limits

1. The maximum allowable emissions from this source shall not exceed the emission rates listed in Tables 1 and 2.

2. Visible emissions during startup, shutdown, or period of part load operation shall not exceed 20% opacity during any 6-minute period. At full load operation, visible emissions shall not exceed 10% opacity.

Operating Rates

3. This source is allowed to operate continuously (8760 hours per year).

4. This source is allowed to use natural gas as the primary fuel and low sulfur No. 2 distillate oil as the secondary fuel up to 1,000 hours per year. Distillate fuel oil No. 2 (0.05% S) shall not be burned if natural gas is available.

5. The permitted materials and utilization rates for the combined cycle gas turbine shall not exceed the values as follows:

40 MW Simple Cycle Turbine

a) The maximum heat input of 371 MMBtu/hr (LHV) at ISO conditions (base load) for distillate fuel oil No. 2.

b) The maximum heat input of 367 MMBtu/hr (LHV) at ISO conditions (base load) for natural gas.

SPECIFIC CONDITIONS:

120 MW Combined Cycle Turbine

a) The maximum heat input of 928 MMBtu/hr (LHV) at ISO conditions (base load) for distillate fuel oil No. 2.

b) The maximum heat input of 869 MMBtu/hr (LHV) at ISO conditions (base load) for natural gas.

6. Any change in the method of operation, equipment or operating hours shall be submitted to DER's Bureau of Air Regulation.

7. Any other operating parameters established during compliance testing and/or inspection that will ensure the proper operation of this facility may be included in the operating permit.

Compliance Determination

8. Compliance with the NO_x, SO_2, CO, PM, PM_{10}, and VOC standards shall be determined (while operating at 95-100% of the permitted maximum heat rate input corresponding to the particular ambient conditions) within 180 days of initial operation of the maximum capability of the unit and annually thereafter, by the following reference methods as described in 40 CFR 60, Appendix A (July, 1991 version) and adopted by reference in F.A.C. Rule 17-2.700.

- Method 1 — Sample and Velocity Traverses
- Method 2 — Volumetric Flow Rate
- Method 3 — Gas Analysis
- Method 5 or Method 17 — Determination of Particulate Emissions from Stationary Sources
- Method 9 — Visual Determination of the Opacity of Emissions from Stationary Sources
- Method 8 — Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources (for fuel oil firing only)
- Method 10 — Determination of Carbon Monoxide Emissions from Stationary Sources
- Method 20 — Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines
- Method 25A — Determination of Total Gaseous Organic Concentrations Using a Flame Ionization Analyzer

Other DER approved methods may be used for compliance testing after prior Departmental approval.

SPECIFIC CONDITIONS:

PM

9. Method 5 or Method 17 must be performed on each unit to determine the initial compliance status of particulate matter emissions of the unit. Thereafter, the opacity emissions test may be used unless 10% opacity is exceeded.

SO2

10. Compliance with the SO_2 emission limit can also be determined by calculations based on fuel analysis using ASTM D4294 for the sulfur content of liquid fuels and ASTM D3246-81 for sulfur content of gaseous fuel.

Be

11. Trace elements of Beryllium (Be) shall be tested during initial compliance test using EMTIC Interim Test Method. As an alternative, Method 104 may be used; or Be may be determined from fuel sample analysis using either Method 7090 or 7091, and sample extraction using Method 3040 as described in the EPA solid waste regulations SW 846.

Hg

12. Mercury (Hg) shall be tested during initial compliance test using EPA Method 101 (40 CFR 61, Appendix B) or fuel sampling analysis using methods acceptable to the Department.

13. During performance tests, to determine compliance with the allowable NO_x standard, measured NO_x emissions at 15 percent oxygen will be adjusted to ISO ambient atmospheric conditions by the following correction factor:

$$NO_x = (NO_{x\ obs}) \left(\frac{P_{ref}}{P_{obs}}\right)^{0.5} e^{19\,(H_{obs} - 0.00633)} \left(\frac{288°K}{T_{AMB}}\right)^{1.53}$$

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 (1 atmosphere) ambient pressure.

P_{obs} = Measured combustor inlet absolute pressure at test ambient pressure.

H_{obs} = Specific humidity of ambient air at test.

e = Transcendental constant (2.718).

T_{AMB} = Temperature of ambient air at test (°K).

SPECIFIC CONDITIONS:

14. Test results will be the average of 3 valid runs. The Central District office will be notified at least 30 days in writing in advance of the compliance test(s). The sources shall operate between 95% and 100% of permitted capacity during the compliance test(s) as adjusted for ambient temperature. Compliance test results shall be submitted to the Central District office no later than 45 days after completion.

15. The permittee shall comply with the following by 1/1/98:

a) For the combined cycle unit (PG7111EA), if the 15 (gas)/42 (oil) ppmv emission rates cannot be met by 1/1/98, SCR will be installed. Hence, the permittee shall install a duct module suitable for future installation of SCR equipment.

b) For the simple cycle unit (LM6000), the manufacturer will attempt to achieve a maximum NO_x emission level of 15 (gas)/42 (oil) ppmv by 1/1/98. Should this level of control not be achieved when the compliance demonstration stack tests are performed, the permittee must provide the Department with expected compliance dates which will be updated annually. After 1/1/98, if the compliance schedule has not been met, the Department may require SCR be installed since the exhaust temperature has an acceptable range for SCR installation.

16. The permittee shall comply with the following requirements:

(a) Install, calibrate, maintain, and operate a continuous emission monitor in each stack to measure and record the nitrogen oxides emissions from each source. The continuous emission monitor must comply with 40 CFR 60, Appendix B, Performance Specification 2 (July 1, 1992);

(b) A continuous monitoring system shall be installed to monitor and record the fuel consumption on each unit. While water injection is being utilized for NO_x control, the water to fuel ratio at which compliance is achieved shall be incorporated into the permit and shall be continuously monitored. The system shall meet the requirements of 40 CFR Part 60, Subpart GG;

(c) In addition, literature on equipment selected shall be submitted as it becomes available. A CT-specific graph of the relationship between NOx emissions and water injection and also another of ambient temperature and heat inputs to the CT shall be submitted to DER's Central District office and the Bureau of Air Regulation.

17. Sulfur and nitrogen content and lower heating value of the fuel being fired in the combustion turbines shall be determined as specified in 40 CFR 60.334(b). The records of fuel oil usage shall

SPECIFIC CONDITIONS:

be kept by the company for a two-year period for regulatory agency inspection purposes. For sulfur dioxide, periods of excess emissions shall be reported if the fuel being fired in the gas turbine exceeds 0.05 percent sulfur by weight.

Rule Requirements

18. This source shall comply with all applicable provisions of Chapter 403, Florida Statutes, Chapters 17-209 through 17-297, Florida Administrative Code and 40 CFR (July, 1991 version).

19. The sources shall comply with all requirements of 40 CFR 60, Subpart GG, and F.A.C. Rule 17-296.800, Standards of Performance for Stationary Gas Turbines.

20. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (F.A.C. Rule 17-210.300(1)).

21. This source shall be in compliance with all applicable provisions of F.A.C. Rules 17-210.650: Circumvention; 17-210.700: Excess Emissions; 17-296.800: Standards of Performance for New Stationary Sources (NSPS); 17-297: Stationary Sources Emission Monitoring; and, 17-4.130: Plant Operation-Problems.

22. If construction does not commence within 18 months of issuance of this permit, then the permittee shall obtain from DER a review and, if necessary, a modification of the control technology and allowable emissions for the unit(s) on which contruction has not commenced (40 CFR 52.21(r)(2)).

23. Quarterly excess emission reports, in accordance with the July 1, 1992 version of 40 CFR 60.7 and 60.334 shall be submitted to DER's Central District office.

24. Fugitive dust emissions, during the construction period, shall be minimized by covering or watering dust generation areas.

25. Pursuant to F.A.C. Rule 17-210.300(2), Air Operating Permits, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur, nitrogen contents and the lower heating value of the fuel being fired, fuel usage, hours of operation, air emissions limits, etc. Annual reports shall be sent to the Department's Central District office by March 1 of each calendar year.

PERMITTEE:
Kissimmee Utility Authority

Permit Number: AC 49-205703
PSD-FL-182
Expiration Date: March 31, 1995

SPECIFIC CONDITIONS:

26. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

27. An application for an operation permit must be submitted to the Central District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

Issued this 7 day
of April, 1993

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Virginia B. Wetherell

Virginia B. Wetherell
Secretary

KISSIMMEE UTILITY AUTHORITY - AC49-205703 (PSD-FL-182)
40 MW SIMPLE CYCLE GAS TURBINE

Table 1 - Allowable Emission Rates

Pollutant	Fuel[A]	Allowable Emission[C] Standard/Limitation	Basis
	Gas	15 ppmvd @ 15% O_2 & ISO (22 lbs/hr; 90.86 TPY)[B]	BACT
NO_x	Gas	25 ppmvd @ 15% O_2 & ISO (36 lbs/hr; 148.68 TPY)	BACT
	Oil*	42 ppmvd @ 15% O_2 & ISO (63 lbs/hr; 15.75 & 31.5 TPY)	BACT
	Oil**	42 ppmvd @ 15% O_2 & ISO (63 lbs/hr; 275.9 TPY)	
CO	Gas	30 ppmvd (40 lbs/hr; 165.2 TPY)	BACT
	Oil*	63 ppmvd (76 lbs/hr; 19 & 38 TPY)	BACT
	Oil**	63 ppmvd (76 lbs/hr; 332.9 TPY)	
VOC	Gas	1.4 lbs/hr; 5.8 TPY	BACT
	Oil*	3 lbs/hr; 0.75 & 1.5 TPY	BACT
	Oil**	3 lbs/hr; 13.1 TPY	
PM_{10}	Gas	0.0245 lb/MMBtu	BACT
	Oil	0.0323 lb/MMBtu	BACT
SO_2	Gas	nil	BACT
	Oil	20 lbs/hr; 5.0 & 10 TPY	BACT
	Oil**	20 lbs/hr; 87.6 TPY	
H_2SO_4	Gas	nil	BACT
	Oil*	2.2 lbs/hr; 0.55 & 1.1 TPY	BACT
	Oil**	2.2 lbs/hr; 9.6 TPY	
Opacity	Gas	10% opacity[D]	BACT
	Oil	10% opacity[D]	BACT
Hg	Oil	3.1×10^{-6} lb/MMBtu	Appl.
As	Oil	4.2×10^{-6} lb/MMBtu	Appl.
Be	Oil	2.5×10^{-6} lb/MMBtu	BACT
Pb	Oil	2.8×10^{-5} lb/MMBtu	Appl.

A) Fuel: Natural Gas: Emissions are based on 8260 hours per year operating time.
Fuel: No. 2 Distillate Fuel Oil (0.05% S):
* Emissions are based on 500 and 1000 hours per year operating time.
** Emissions are based on 8760 hours per year burning oil. Continuous oil burning (8760 hrs/yr) is not allowed unless natural gas is not available.

B) The NO_x maximum limit will be lowered to 15 ppm by 1/1/98 using appropriate combustion technology improvements. Should this level of control not be achieved when the compliance demonstration stack tests are performed, the permittee must provide the Department with the expected compliance dates which will be updated annually. After 1/1/98, if the compliance schedule has not been met, the Department may require SCR be installed since the exhaust temperature has an acceptable range for SCR installation.

C) Emission rates are based on 100% load and at ISO conditions.

D) 10% opacity at full load conditions.

KISSIMMEE UTILITY AUTHORITY - AC49-205703 (PSD-FL-182)
120 MW COMBINED CYCLE GAS TURBINE

Table 2 - Allowable Emission Rates

Pollutant	Fuel[A]	Allowable Emission[C] Standard/Limitation	Basis
	Gas	15 ppmvd @ 15% O_2 & ISO (53 lbs/hr; 219 TPY)[B]	BACT
NO_x	Gas	25 ppmvd @ 15% O_2 & ISO (98 lbs/hr, 405 TPY)	BACT
	Oil*	42 ppmvd @ 15% O_2 & ISO (170 lbs/hr; 43 & 85 TPY)	BACT
	Oil**	42 ppmvd @ 15% O_2 & ISO (170 lbs/hr; 745 TPY)	
CO	Gas	20 ppmvd (54 lbs/hr; 223 TPY)	BACT
	Oil*	20 ppmvd (65 lbs/hr; 16 & 32.5 TPY)	BACT
	Oil**	20 ppmvd (65 lbs/hr; 285 TPY)	
VOC	Gas	2.0 lbs/hr; 8.3 TPY	BACT
	Oil*	5 lbs/hr; 1.3 & 2.5 TPY	BACT
	Oil**	5 lbs/hr; 21.9 TPY	
PM_{10}	Gas	0.0100 lb/MMBtu	BACT
	Oil	0.0162 lb/MMBtu	BACT
SO_2	Gas	nil	BACT
	Oil*	52 lbs/hr; 13 & 26 TPY	BACT
	Oil**	52 lbs/hr; 228 TPY	
H_2SO_4	Gas	nil	BACT
	Oil*	5.72 lbs/hr; 1.4 & 2.86 TPY	BACT
	Oil**	5.72 lbs/hr; 25.1 TPY	
Opacity	Gas	10% opacity[D]	BACT
	Oil	10% opacity[D]	BACT
Hg	Oil	3.0×10^{-6} lb/MMBtu	Appl.
As	Oil	4.2×10^{-6} lb/MMBtu	Appl.
Be	Oil	2.5×10^{-6} lb/MMBtu	BACT
Pb	Oil	2.8×10^{-5} lb/MMBtu	Appl.

A) Fuel: Natural Gas: Emissions are based on 8260 hours per year operating time.
Fuel: No. 2 Distillate Fuel Oil (0.05% S):
* Emissions are based on 500 and 1000 hours per year operating time.
** Emissions are based on 8760 hours per year burning oil. Continuous oil burning (8760 hrs/yr) is not allowed unless natural gas is not available.

B) The NO_x maximum limit will be lowered to 15 ppm by 1/1/98 using appropriate combustion technology improvements or SCR.

C) Emission rates are based on 100% load and at ISO conditions.

D) 10% opacity at full load conditions.

Best Available Control Technology (BACT) Determination
Kissimmee Utility Authority
Osceola County
PSD-FL-182

The applicant proposes to install two combustion turbine generators at their facility near Intercession City, Osceola County. These generator systems will consist of: 1) one nominal 80 megawatt (MW) General Electric PG7111EA combined cycle combustion turbine (CCCT), with exhaust through a heat recovery steam generator (HRSG), which will be used to power a nominal 40 MW steam turbine and 2) a 40 MW General Electric LM6000 simple cycle combustion turbine (SCCT).

The PG7111EA combustion turbine will be capable of operating on a combined and a simple cycle mode. The LM6000 will operate on a simple cycle mode. The applicant has requested to burn natural gas or fuel oil No. 2, with a 0.05 percent sulfur content, on a continuous basis (8,760 hrs/year). The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility based on 100 percent capacity factor, ISO conditions, and type of fuel fired to be as follows:

Pollutant	Emissions (TPY) Oil		Emissions (TPY) Gas		PSD Significant Emission Rate (TPY)
	PG7111EA	LM6000	PG7111EA	LM6000	
NO_x	744.6	275.9	429.2	157.7	40
SO_2	227.8	87.6	nil	nil	40
PM/PM_{10}	65.7	52.6	30.7	39.4	25/15
CO	284.7	332.9	236.5	175.2	100
VOC	21.9	13.1	8.8	6.1	40
H_2SO_4	25.1	9.6	nil	nil	7
Be	0.0099	0.0035	---	---	0.0004
Hg	0.012	0.005	---	---	0.1
Pb	0.044	0.141	---	---	0.6

Florida Administrative Code (F.A.C.) Rule 17-2.500(2) (f) (3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

Date of Receipt of a BACT Application

June 2, 1992

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	25 ppmvd @ 15% O_2 (natural gas burning) 42 ppmvd @ 15% O_2 (for oil firing) PG7111(EA) Control Technology: Low NO_x Burners GE LM6000 Control Technology: Water Injection

SO_2	0.3% sulfur by weight (but limited to 0.05% sulfur for modeling purposes)
CO, VOC	Combustion Control
PM/PM_{10}	Combustion Control

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-296, Air Pollution, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that in making the BACT determination the Department shall give consideration to:

(a) Any Environmental Protection Agency determination of Best Available Control Technology pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determinations of any other state.

(d) The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine for the emission source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source in question, than the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The air pollutant emissions from combined cycle power plants can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the emissions can be classified as follows:

- o Combustion Products (e.g., particulates). Controlled generally by good combustion of clean fuels.
- o Products of Incomplete Combustion (e.g., CO). Control is largely achieved by proper combustion techniques.
- o Acid Gases (e.g., NO_x). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulates, sulfur dioxide, fluorides, sulfuric acid mist, etc,), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

BACT POLLUTANT ANALYSIS

COMBUSTION PRODUCTS

Particulate Matter (PM/PM_{10})

The design of this system ensures that particulate emissions will be minimized by combustion control and the use of clean fuels. The particulate emissions from the combustion turbines when burning natural gas and fuel oil will not exceed 15 lbs/hr (oil) and 7 lbs/hr (gas) for the PG7111 and 12 lbs/hr (oil) and 9 lbs/hr (gas) for the LM6000. The Department accepts the applicant's proposed control for particulate matter and heavy metals.

Lead, Mercury, Beryllium (Pb, Hg, Be)

The Department agrees with the applicant's rationale that there are no feasible methods to control lead, mercury, and beryllium; except by limiting the inherent quality of the fuel.

Although the emissions of these toxic pollutants could be controlled by particulate control devices, such as a baghouse or scrubber, the amount of emission reductions would not warrant the added expense. As this is the case, the Department does not believe that the BACT determination would be affected by the emissions of these pollutants.

PRODUCTS OF INCOMPLETE COMBUSTION

Carbon Monoxide (CO) and Volatile Organic Compounds (VOC)

The emissions of carbon monoxide exceed the PSD significant emission rate of 100 TPY. The applicant has indicated that the carbon monoxide emissions from the proposed combined cycle turbine with a "quiet combustor" are 10 ppmv for natural gas firing and 20 ppmv for fuel oil firing. However, for a dry low NO_x combustor, the emission limit is 20 ppmvd for both oil and gas. For the simple cycle CT, the CO emissions for firing natural gas and fuel oil are 30 ppmv and 63 ppmv, respectively.

The majority of BACT emissions limitations have been based on combustion controls for carbon monoxide and volatile organic compounds minimization, however, additional control is achievable through the use of catalytic oxidation. Catalytic oxidation is a postcombustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10-ppm range (corrected to dry conditions).

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CT/HRSG combinations, the oxidation catalyst can be located directly after the CT or in the HRSG. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency.

Due to the oxidation of sulfur compounds and excessive formation of H_2SO_4 mist emissions, oxidation catalysts are not considered to be technically feasible for gas turbines fired with fuel oil. Catalytic oxidation has not been demonstrated on a continuous basis when using fuel oil.

Use of oxidation catalyst technology would be feasible for a natural gas-fired unit; however, the cost effectiveness of $4,437 per ton for the LM6000 and $10,560 per ton for the PG7110EA of CO/VOC removed will have an economic impact on this project.

The Department is in agreement with the applicant's proposal of combustor design and good operating practices as BACT for CO and VOCs for this cogeneration project.

ACID GASES

Nitrogen Oxides (NO_x)

The emissions of nitrogen oxides represent a significant proportion of the total emissions generated by this project, and need to be controlled if deemed appropriate. As such, the applicant presented an extensive analysis of the different available technologies for NO_x control.

The applicant has stated that BACT for nitrogen oxides will be met by using water injection and advanced combustor design to limit emissions to 25 ppmvd (corrected to 15% O_2) when burning natural gas and 42 ppmvd (corrected to 15% O_2) when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NO_x emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system.

Selective catalytic reduction is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction will decrease to approximately 86 percent.

The effect of exhaust gas temperature on NO_x reduction depends on the specific catalyst formulation and reactor design. Generally, SCR units can be designed to achieve effective NO_x control over a 100-300°F operating window within the bounds of 450-800°F, although recently developed zeolite-based catalysts are claimed to be capable of operating at temperatures as high as 950°.

Most commercial SCR systems operate over a temperature range of about 600-750°F. At levels above and below this window, the specific catalyst formulation will not be effective and NO_x reduction will decrease. Operating at high temperatures can permanently damage the catalyst through sintering of surfaces.

Increased water vapor content in the exhaust gas (as would result from water or steam injection in the gas turbine combustor) can shift the operating temperature window of the SCR reactor to slightly higher levels.

As stated by the applicant, the exhaust temperatures of the proposed simple cycle CTs for this site are between 600°F to 800°F.

At temperatures of 1,000°F and above, the zeolite catalyst (reported to operate within 600°F to 950°F) will be irreparably damaged. In this case, application of an SCR system using a zeolite catalyst on a simple-cycle operation appears to be technically feasible.

However, the applicant has rejected using SCR on the simple cycle CT because of economic and environmental impacts.

Although technically feasible, the applicant has also rejected using SCR on the combined cycle because of economic, energy, and environmental impacts. The applicant has identified the following limitations:

a) Reduced power output.
b) Emissions of unreacted ammonia (slip).
c) Disposal of hazardous waste generated (spend catalyst).
d) Ammonium bisulfate and ammonium sulfate particulate emissions (ammonium salts) due to the reaction of NH_3 with SO_3 present in the exhaust gases.
e) Cost effectiveness for the application of SCR technology to the Kissimmee Utility project was considered to be $9,879 per ton of NO_x removed for the PG7111EA and $13,700 per ton of NO_x removed for the LM6000 when burning natural gas.

Since SCR has been determined to be BACT for several combined cycle facilities, the EPA has clearly stated that there must be unique circumstances to consider the rejection of such control on the basis of economics.

In a recent letter from EPA Region IV to the Department regarding the permitting of a combined cycle facility (Tropicana Products, Inc.), the following statement was made:

> "In order to reject a control option on the basis of economic considerations, the applicant must show why the costs associated with the control are significantly higher for this specific project than for other similar projects that have installed this control system or in general for controlling the pollutant."

For fuel oil firing, the cost associated with controlling NO_x emissions must take into account the potential operating problems that can occur with using SCR in the oil firing mode.

A concern associated with the use of SCR on combined cycle projects is the formation of ammonium bisulfate. For the SCR process, ammonium bisulfate can be formed due to the reaction of sulfur in the fuel and the ammonia injected. The ammonium bisulfate formed has a tendency to plug the tubes of the heat recovery steam generator leading to operational problems. As this is the case, SCR has been judged to be technically infeasible for oil firing in some previous BACT determinations.

The latest information available now indicates that SCR can be used for oil firing provided that adjustments are made in the ammonia to NO_x injection ratio. For natural gas firing operation, NO_x emissions can be controlled with up to a 90 percent efficiency using a 1 to 1 or greater ammonia injection ratio. By lowering the injection ratio for oil firing, testing has indicated that NO_x can be controlled with efficiencies ranging from 60 to 80 percent. When the injection ratio is lowered there is not a problem with ammonium bisulfate formation since essentially all of the ammonia is able to react with the nitrogen oxides present in the combustion gases. Based on this strategy SCR has been both proposed and established as BACT for oil fired combined cycle facilities with NO_x emission limits ranging from 11.7 to 25 ppmvd depending on the efficiency of control established.

The applicant has indicated that the total levelized annual operating cost to install SCR for this project at 100 percent capacity factor and burning natural gas is $2,944,000 for the PG7111EA and $1,589,000 for the LM6000. Taking into consideration the total annual cost, a cost/benefit analysis of using SCR can now be developed.

For the PG7111EA combined cycle combustion turbine, based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions using low NO_x burner will be 372 tons/year (natural gas) and 700 tons/year (oil firing). Assuming that SCR would reduce the NO_x emissions by 80%, about 74 tons of NO_x (natural gas) and 140 tons of NO_x (oil) would be emitted annually. When this reduction (298 TPY natural gas and 560 TPY oil) is taken into consideration with the total levelized annual operating cost of $2,944,000 (natural gas) and $3,424,000 (oil firing); the cost per ton of controlling NO_x is $9,879 (natural gas) and $6,114 (oil), respectively. These calculated costs are higher than has previously been approved as BACT.

For the simple cycle combustion turbine, based on the information supplied by the applicant, it is estimated that the maximum annual NO_x emissions using water injection will be 145 tons/year (natural gas) and 250 tons/year (oil firing). Assuming that SCR would reduce the NO_x emissions by 80%, about 29 tons of NO_x (natural gas) and 50 tons of NO_x (oil firing) would be emitted annually. When this reduction (116 TPY natural gas and 200 TPY oil) is taken into consideration with the total levelized annual operating cost of $1,589,000 (natural gas) and $1,840,000 (oil firing); the cost per ton of controlling NO_x is $13,700 (natural gas) and $9,200 (oil), respectively. These calculated costs are higher than has previously been approved as BACT.

A review of the latest DER BACT determinations show limits of 15 ppmvd (natural gas) using low-NO_x burn technology for combined cycle turbines. General Electric is currently developing programs using both steam/water injection and dry low NO_x combustor to achieve NO_x emission control level of 9 ppm when firing natural gas. Therefore, since this technology will be available by 1997, the Department has accepted the water injection (LM6000), low NO_x burner design (PG7111EA), and the 25 ppmvd (natural gas)/42 ppmvd (oil) at 15% O_2 as BACT for a limited time (up to 1/1/98).

Sulfur Dioxide(SO_2) and Sulfuric Acid Mist (H_2SO_4)

The applicant has stated that sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) emissions when firing fuel oil will be controlled by using fuel oil with a maximum sulfur content of 0.05 % by weight. This will result in an annual emission rate of 18 tons SO_2 per year and 2 tons H_2SO_4 mist per year (operating at 500 hours per year).

In accordance with the "top down" BACT review approach, only two alternatives exist that would result in more stringent SO_2 emissions. These include the use of a lower sulfur content fuel oil or the use of wet lime or limestone-based scrubbers, otherwise known as flue gas desulfurization (FGD).

In developing the NSPS for stationary gas turbines, EPA recognized that FGD technology was inappropriate to apply to these combustion units. EPA acknowledged in the preamble of the proposed NSPS that "Due to the high volumes of exhaust gases, the cost of flue gas desulfurization (FGD) to control SO_2 emissions from stationary gas turbines is considered unreasonable."(23). EPA reinforced this point when, later on in the preamble, they stated that "FGD... would cost about two to three times as much as the gas turbine."(23). The economic impact of applying FGD today would be no different.

Furthermore, the application of FGD would have negative environmental and energy impacts. Sludge would be generated that would have to be disposed of properly, and there would be increased utility (electricity and water) costs associated with the operation of a FGD system. Finally, there is no information in the open literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

The elimination of flue gas control as a BACT option then leaves the use of low sulfur fuel oil as the next option to be investigated. Kissimmee Utility Authority, as stated above, has proposed the use of No. 2 fuel oil with a 0.05% sulfur by weight as BACT for this project. The Department accepts their proposal as BACT for this project.

BACT Determination by DER

NO_x Control

The information that the applicant presented and Department calculations indicates that the cost per ton of controlling NO_x for these turbines [$9,879 (gas) PG7111EA, $6,114 (oil) PG7111EA, $13,700 (gas) LM6000, and $9,200 (oil) LM6000] is high compared to other BACT determinations which require SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_x control is not justifiable as BACT at this time.

A review of the permitting activities for combined cycle proposals across the nation indicates that SCR has been required and most recently proposed for installations with a variety of operating conditions (i.e., natural gas, fuel oil, and various capacity factors). Although, the cost and other concerns expressed by the applicant are valid, the Department, in this case, is willing to accept water injection and low NO_x burner design as BACT for this project for a limited time (up to 12/31/97).

It is the Department's understanding that General Electric is developing programs for the PG7111EA and the LM6000, using either steam/water injection or dry low NO_x combustor technology to achieve a NO_x emission control level of 9 ppm when firing natural gas. Therefore, the Department has determined that the following BACT will apply by 1/1/98.

a) For the combined cycle unit (PG7111EA), if the 15 (gas)/42 (oil) ppmv emission rates cannot be met by 1/1/98, SCR will be installed. Hence, the permittee shall install a duct module suitable for future installation of SCR equipment.
b) For the simple cycle unit (LM6000), the manufacturer will attempt to achieve a maximum NO_x emission level of 15 (gas)/42 (oil) ppmv by 1/1/98. Should this level of control not be achieved, the permittee must notify the Department of the expected compliance date by 1/1/97.
c) For both turbines (PG7111EA and LM6000), when the manufacturer achieves an even lower NO_x emission level than 15 (gas)/42 (oil) ppmv, this level may become a condition of this permit.

SO_2 Control

BACT for sulfur dioxide is the burning of fuel oil No. 2 with 0.05% sulfur content by weight.

VOC and CO Control

Combustion control will be considered as BACT for CO and VOC when firing natural gas.

Other Emissions Control

The emission limitations for PM and PM_{10}, Be, Pb, and Hg are based on previous BACT determinations for similar facilities.

The emission limits for Kissimmee Utility Authority project are thereby established as follows:

120 MW COMBINED CYCLE COMBUSTION TURBINE

Pollutant	Emission Standards/Limitations Oil(a)	Gas(b)	Method of Control
NO_x	42 ppmv	25 ppmv(c)	Water Injection/ Quiet Combustor or Dry Low NO_x Combustor
		15 ppmv	Water Injection/Dry Low NO_x Combustor
CO	65 lbs/hr	54 lbs/hr	Combustion
PM & PM10	15 lbs/hr	7 lbs/hr	Combustion
SO_2	52 lbs/hr	nil	No. 2 Fuel Oil (0.05% S)
H_2SO_4	5.7 lbs/hr	nil	No. 2 Fuel Oil (0.05% S)
VOC	5 lbs/hr	2 lbs/hr	Combustion
Hg	3.0×10^{-6} lb/MMBtu		Fuel Quality
Pb	2.8×10^{-5} lb/MMBtu		Fuel Quality
Be	2.5×10^{-6} lb/MMBtu		Fuel Quality

(a) No. 2 fuel oil with a maximum of 0.05% sulfur by weight.
(b) Natural gas/fuel oil 8260/500 hours per year. Natural gas/fuel oil 7760/1000 hours per year. Continuous burning of No. 2 fuel oil (8760 hrs/yr) is not allowed unless natural gas is not available.
(c) Initial NO_x emission rates for natural gas firing shall not exceed 25 ppmvd at 15% oxygen on a dry basis. The permittee shall achieve NO_x emissions of 15 ppmvd at 15% oxygen at the earliest achievable date based on dry low NO_x combustor

injection technology or any other technology available, but no later than 1/1/98. Should this level of control not be achieved, the permitte shall install SCR.

40 MW SIMPLE CYCLE COMBUSTION TURBINE

Pollutant	Emission Standards/Limitations Oil(a)	Gas(b)	Method of Control
NO_x	42 ppmv	25 ppmv(c) 15 ppmv	Water Injection Dry Low NO_x Combustor
CO	76 lbs/hr	40 lbs/hr	Combustion
PM & PM10	12 lbs/hr	9 lbs/hr	Combustion
SO_2	20 lbs/hr	nil	No. 2 Fuel Oil (0.05% S)
H_2SO_4	2.2 lbs/hr	nil	No. 2 Fuel Oil (0.05% S)
VOC	3 lbs/hr	1.4 lbs/hr	Combustion
Hg	3.0×10^{-6} lb/MMBtu		Fuel Quality
Pb	2.8×10^{-5} lb/MMBtu		Fuel Quality
Be	2.5×10^{-6} lb/MMBtu		Fuel Quality

(a) No. 2 fuel oil with a maximum of 0.05% sulfur by weight.

(b) Natural gas/fuel oil 8260/500 hours per year. Natural gas/fuel oil 7760/1000 hours per year. Continuous firing of fuel oil (8760 hrs/yr) is not allowed unless natural gas is not available.

(c) Initial NO_x emission rates for natural gas firing shall not exceed 25 ppmvd at 15% oxygen on a dry basis. The permittee shall achieve NO_x emissions of 15 ppmvd at 15% oxygen at the earliest achievable date based on dry low NO_x combustor technology or any other technology available, but no later than 1/1/98. Should this level of control not be achieved when the compliance demonstration stack tests are performed, the permittee must provide the Department with the expected compliance dates which will be updated annually. After 1/1/98, if the compliance schedule has not been met, the Department may require SCR be installed since the exhaust temperature has an acceptable range for SCR installation.

Details of the Analysis May be Obtained by Contacting:

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Bureau of Air Regulation
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Recommended by:	Approved by:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Virginia B. Wetherell, Secretary Dept. of Environmental Regulation
April 1, 1993 Date	April 7, 1993 Date