TITLE V AIR PERMIT APPLICATION

Kissimmee Utility Authority

Florida Municipal Power Agency

Cane Island
Unit 3

building a world of difference™ | BLACK & VEATCH

A.K. (BEN) SHARMA, P.E.
Vice President of Power Supply
E-mail: BSHARMA@KUA.COM

KISSIMMEE UTILITY AUTHORITY

P.O. BOX 423219, KISSIMMEE, FLORIDA 34742-3219
(407) 933-7777 FAX: 407-847-0787

October 15, 2001

Mr. C.H. Fancy, P.E.
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Subject: Cane Island Title V Operating Permit Application
Project No.: 0970043-010-AV

Dear Mr. Fancy:

Enclosed please find one original and three copies of the Cane Island Title V Operating Permit.

If you have any questions please do not hesitate to contact me at (407) 933-7777 ext. 1232

Sincerely,

AK Sharma

A.K. Ben Sharma, P.E.
Vice President of Power Supply

AKS/rw

Enclosures

RECEIVED
OCT 17 2001
BUREAU OF AIR REGULATION

APPLICATION FOR A TITLE V OPERATING PERMIT REVISION FOR THE CANE ISLAND POWER PARK UNIT 3

KISSIMMEE UTILITY AUTHORITY

PREPARED BY
BLACK & VEATCH CORPORATION

OCTOBER 2001
PROJECT NO. 65270

APPLication Info

Department of Environmental Protection

Division of Air Resources Management

APPLICATION FOR AIR PERMIT - TITLE V SOURCE

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

I. APPLICATION INFORMATION

Identification of Facility

1. Facility Owner/Company Name: Kissimmee Utility Authority	
2. Site Name: Cane Island Power Park	
3. Facility Identification Number: 0970043	[ ] Unknown
4. Facility Location: Kissimmee Utility Authority, Cane Island Power Park Street Address or Other Locator: 6075 Old Tampa Highway City: Intercession City County: Osceola Zip Code: 33848-9999	
5. Relocatable Facility? [ ] Yes [X] No	6. Existing Permitted Facility? [X] Yes [ ] No

Application Contact

1. Name and Title of Application Contact: A. K. Sharma, Director of Power Supply	
2. Application Contact Mailing Address: Organization/Firm: Kissimmee Utility Authority Street Address: 1701 West Carroll Street City: Kissimmee State: Florida Zip Code: 34742	
3. Application Contact Telephone Numbers: Telephone: (407)933-7777	Fax: (407)847-0787

Application Processing Information (DEP Use)

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

Purpose of Application

Air Operation Permit Application

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

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

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

Current construction permit number:____________________

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

Current construction permit number: PSD-FL-254 (PA98-38)

Operation permit number to be revised: 0970043-002-AV

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

Operation permit number to be revised/corrected:____________________

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

Operation permit number to be revised:____________________

Reason for revision:____________________

Air Construction Permit Application

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

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

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

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

Owner/Authorized Representative or Responsible Official

1. Name and Title of Owner/Authorized Representative or Responsible Official: A. K. Sharma, Director of Power Supply	
2. Owner/Authorized Representative or Responsible Official Mailing Address: Organization/Firm: Kissimmee Utility Authority Street Address: 1701 West Carroll Street City: Kissimmee State: Florida Zip Code: 34742	
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*(check here [ ], if so) or the responsible official (check here [ ], if so) of the Title V source addressed in this application, whichever is applicable. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof. I understand that a permit, if granted by the Department, cannot be transferred without authorization from the Department, and I will promptly notify the Department upon sale or legal transfer of any permitted emissions unit.* AK Sharma 10/12/2001 Signature Date	

* Attach letter of authorization if not currently on file.

Professional Engineer Certification

1. Professional Engineer Name: Mark Andrew Wiitanen Registration Number: 55122	
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: (734)622 - 8661 Fax: (734) 622 - 8700	

4. Professional Engineer Statement:

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

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

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

If the purpose of this application is to obtain a Title V source air operation permit (check here [ ], if so), I further certify that each emissions unit described in this Application for Air Permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance schedule is submitted with this application.

If the purpose of this application is to obtain an air construction permit for one or more proposed new or modified emissions units (check here [ ], if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

If the purpose of this application is to obtain an initial air operation permit or operation permit revision for one or more newly constructed or modified emissions units (check here [ ], if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Mark A. Wiitanen
Signature

October 9, 2001
Date

(seal)

* Attach any exception to certification statement.

Scope of Application

Emissions Unit ID	Description of Emissions Unit	Permit Type	Processing Fee
003	One nominal 167 Megawatt Gas Combustion Turbine-Electrical Generator	N/A	N/A
004	1.0 Million Gallon Fuel Oil Storage Tank	N/A	N/A
005	One 44mmBtu/hr Duct Burner in a Supplementally Fired Heat Recovery Steam Generator (and 80-90 MW Steam Electrical Turbine)	N/A	N/A
006	Cooling Tower INSIGNIFICANT OR UNREGULATED ?	N/A	N/A

Application Processing Fee

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

Construction/Modification Information

1. Description of Proposed Project or Alterations: Kissimmee Utility Authority (KUA) has constructed a nominal 250 MW natural gas with fuel oil backup combined cycle electrical generating unit (Unit #3) at the Cane Island Power Park. The Cane Island Power Park is currently operating under Title V Permit Number 0970043-002-AV, which includes Units #1and #2. The plant expansion (Unit #3) was built in accordance with Air Construction Permit No. PSD-FL-254. Unit #3 consists of a nominal 167 MW stationary gas combustion turbine-electrical generator burning natural gas with fuel oil as backup, a supplementally gas-fired heat recovery steam generator to raise sufficient steam to achieve 250 MW in combined cycle operation, an 80-90 MW steam electric generator, a 44 mmBtu/hr heat input duct burner, a selective catalytic reduction unit and ancillary equipment, ammonia storage, a 130-foot stack, and a 100-foot bypass stack for simple cycle operation. A new one million gallon above-ground fuel oil storage tank and a new cooling tower will support operation of Unit #3.
2. Projected or Actual Date of Commencement of Construction: November 1999
3. Projected Date of Completion of Construction: September 2001

Application Comment

None

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): 28/16/32		Longitude (DD/MM/SS): 81/31/59	
3. Governmental Facility Code: 4	4. Facility Status Code: A	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment (limit to 500 characters): None			

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 Highway City: Intercession City	State: Florida	Zip Code: 33848-9999
3. Facility Contact Telephone Numbers: Telephone: (407)846-7070	Fax: (407)846-6485	

Facility Regulatory Classifications

Check all that apply:

1. [ ] Small Business Stationary Source?	[ ] Unknown
2. [X] Major Source of Pollutants Other than Hazardous Air Pollutants (HAPs)?	
3. [ ] Synthetic Minor Source of Pollutants Other than HAPs?	
4. [X] Major Source of Hazardous Air Pollutants (HAPs)?	
5. [ ] Synthetic Minor Source of HAPs?	
6. [X] One or More Emissions Units Subject to NSPS?	
7. [ ] One or More Emission Units Subject to NESHAP?	
8. [X] Title V Source by EPA Designation?	
9. Facility Regulatory Classifications Comment (limit to 200 characters): Facility units currently exempt under NESHAPs. The cooling tower is not subject to a NESHAP because chromium-based chemical treatment is not used—the cooling tower is not a major source of HAPs.	

✓

List of Applicable Regulations

Facility-wide applicable regulations here by incorporates by reference the Title V Core.	
List of applicable regulations that all Title V are facilities are presumptively subject.	
Facility-wide applicable regulations specified in Section II of KUA's Title V Air Operating Permit (No. 0970043-002-AV) are hereby incorporated by reference	

B. FACILITY POLLUTANTS

List of Pollutants Emitted

1. Pollutant Emitted	2. Pollutant Classif.	3. Requested Emissions Cap lb/hour	tons/year	4. Basis for Emissions Cap	5. Pollutant Comment
VOC	A				
CO	A				
NOX	A				
PM	A				
PM10	A				
SO2	A				
HAPS	A				

C. FACILITY SUPPLEMENTAL INFORMATION

Supplemental Requirements

1. Area Map Showing Facility Location: [ ] Attached, Document ID:________ [ ] Not Applicable [X] Waiver Requested
2. Facility Plot Plan: [X] Attached, Document ID: Attachment A[ ] Not Applicable [ ] Waiver Requested
3. Process Flow Diagram(s): [ ] Attached, Document ID:________ [ ] Not Applicable [X] Waiver Requested
4. Precautions to Prevent Emissions of Unconfined Particulate Matter: [ ] Attached, Document ID:________ [ ] Not Applicable [X] Waiver Requested
5. Fugitive Emissions Identification: [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
6. Supplemental Information for Construction Permit Application: [ ] Attached, Document ID:________ [X] Not Applicable
7. Supplemental Requirements Comment: None A waiver is requested for Supplemental Requirements 1,3, and 4, as these items are not altered as a result of this application and have previously been submitted within the last 5 years in the following permit applications: • Air Construction Permit PSD-FL-254, Application of August 5, 1998 and Site Certification Application. • Title V Air Operating Permit No. 0970043-002-A, Application of June 1996.

Additional Supplemental Requirements for Title V Air Operation Permit Applications

8. List of Proposed Insignificant Activities: [X] Attached, Document ID: Attachment B [ ] Not Applicable	
9. List of Equipment/Activities Regulated under Title VI: [ ] Attached, Document ID:________ [X] Equipment/Activities On site but Not Required to be Individually Listed [ ] Not Applicable	
10. Alternative Methods of Operation: [ ] Attached, Document ID:________ [X] Not Applicable	
11. Alternative Modes of Operation (Emissions Trading): [ ] Attached, Document ID:________ [X] Not Applicable	
12. Identification of Additional Applicable Requirements: [ ] Attached, Document ID:________ [X] Not Applicable	
13. Risk Management Plan Verification: [ ] Plan previously submitted to Chemical Emergency Preparedness and Prevention Office (CEPPO). Verification of submittal attached (Document ID:________) or previously submitted to DEP (Date and DEP Office:________________________) [ ] Plan to be submitted to CEPPO (Date required:____________________________) [X] Not Applicable	
14. Compliance Report and Plan: [X] Attached, Document ID: Attachment C [ ] Not Applicable	
15. Compliance Certification (Hard-copy Required): [X] Attached, Document ID: Attachment D [ ] Not Applicable	

 Emission Units 003,005

III. EMISSIONS UNIT INFORMATION

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters): The 250 MW combined cycle combustion turbine is comprised of one combustion turbine which exhausts through a heat recovery steam generator (HRSG) with supplemental firing which is used to power a steam turbine.

4. Emissions Unit Identification Number: [ ] No ID
ID: 003, 005 [ ] ID Unknown

5. Emissions Unit Status Code: A	6. Initial Startup Date: 05/23/01	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? [X]

9. Emissions Unit Comment: (Limit to 500 Characters) EU 003- nominal 167 MW combustion turbine. EU 005- Duct burner (44mmBtu/hr) in a supplementally fired HRSG.

Emissions Unit Control Equipment

1.	Control Equipment/Method Description (Limit to 200 characters per device or method): **Simple Cycle Control Technology** • Dry Low NO_X (DLN) combustors to control NOx emissions during periods of natural gas use. DLN also used to minimize CO emissions. • Water injection system to control NOx emissions during periods of distillate fuel oil use. **Combined Cycle Technology** • Selective catalytic reduction system (SCR) to control NOx emissions. • Dry Low NO_X (DLN) combustors to control NOx emissions during periods of natural gas use. DLN also used to minimize CO emissions. • Water injection system to control NOx emissions during periods of distillate fuel oil use. Need CAM plan OK according to [illegible].
2.	Control Device or Method Code(s): 024, 028, 065

Emissions Unit Details

1.	Package Unit: Combustion Turbine-Electrical Generator Manufacturer: General Electric	Model Number: PG7241FA
2.	Generator Nameplate Rating: 250 MW	
3.	Incinerator Information: Dwell Temperature: Dwell Time: Incinerator Afterburner Temperature:	 °F seconds °F

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

Emissions Unit Operating Capacity and Schedule

1.	Maximum Heat Input Rate:	1,696 (@19 F/55% RH)	mmBtu/hr
2.	Maximum Incineration Rate: N/A	lb/hr	tons/day
3.	Maximum Process or Throughput Rate: N/A		
4.	Maximum Production Rate: N/A		
5.	Requested Maximum Operating Schedule:		
		24 hours/day	7 days/week
		52 weeks/year	8,760 hours/year

6. Operating Capacity/Schedule Comment (limit to 200 characters): The following permit note is requested in the operating permit: *The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emission unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits, and to aid in determining future rule applicability. Regular record keeping is not required for heat input. Instead, the owner or operator is expected to determine heat input whenever emission testing is required, to demonstrate at what percentage of the rated capacity that the unit was tested. [Rule 62-210.200, F.A.C. (Definitions-Potential Emissions)]*

- Maximum heat input rate in Field 1 is based on natural gas firing, LHV.
- Maximum heat input rate during No.2 fuel oil firing is 1,910 mmBtu/hr (@19 F/55% R.H.) LHV.
- No.2 Fuel Oil firing is allowed for 720 hours per year.

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60, Subpart A – General Provisions	Emission unit applicable regulations hereby incorporates by reference the Title V Core List of Applicable Regulations that all Title V sources are presumptively subject.
40 CFR 60, Subpart GG- Standards of Performance for Stationary Gas Turbines	
40 CFR 72, Permits Regulation	
40 CFR 73, Sulfur Dioxide Allowance System	
40 CFR 75, Continuous Emission Monitoring	
62-204.800(7)(b), Federal Regulations Adopted by Reference-Standards of Performance for New Stationary Sources	
62-296.320, General Pollutant Emission Standards	
62-297.520, Stationary Sources-Emissions Monitoring	
40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial Steam Generating Units	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? See Attachment A, #14	2. Emission Point Type Code: 3

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point):
- One 130 ft vertical cylindrical exhaust stack for the HRSG-combined cycle operation.
- One 100 ft vertical cylindrical exhaust stack for simple cycle operation.

4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: N/A

5. Discharge Type Code: V	6. Stack Height: 130 feet	7. Exit Diameter: 18.00 feet
8. Exit Temperature: 173 °F	9. Actual Volumetric Flow Rate: 635,155 acfm	10. Water Vapor: %

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

13. Emission Point UTM Coordinates:

Zone: 17 East (km): 447.722 North (km): 3127.785

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

This emission point data in fields 5-13 represents the combined cycle HRSG stack.

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

Segment Description and Rate: Segment ___1__ of ___2__

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Natural Gas Firing. Natural gas maximum allowable hours are 8,760 hours per year.		
2. Source Classification Code (SCC): 20100201	3. SCC Units: Million cubic feet burned	
4. Maximum Hourly Rate: 1.66	5. Maximum Annual Rate: 14,566	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: 1,020
10. Segment Comment (limit to 200 characters): Maximum Hourly Rate = 1,696 mmBtu/hr/1,020 mmBtu/mmscf = **1.66 mmscf/hr** Maximum Annual Rate = 8,760 hrs/yr x 1,696 mmBtu/hr/1,020 mmBtu/mmscf = **14,566 mmscf/yr**		

Segment Description and Rate: Segment ___2__ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): No. 2 Fuel Oil Firing. No.2 fuel oil maximum allowable hours are 720 hours per year.		
2. Source Classification Code (SCC): 20100101	3. SCC Units: Thousand Gallons Burned	
4. Maximum Hourly Rate: 14.30 thousand gallons/hr	5. Maximum Annual Rate: 10,293.41 thousand gal/yr	6. Estimated Annual Activity Factor:
7. Maximum % Sulfur: 0.05	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit 133.6
11. Segment Comment (limit to 200 characters): Maximum Hourly Rate = 1,910 mmBtu/hr/133.6 mmBtu/thousand gallons = **14.30 Thousand gallons/hr** Maximum Annual Rate = 720 hrs/yr x 1,910 mmBtu/hr/133.6 mmBtu/thousand gallons = **10,293.41 thousand gallons/yr**		

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

1. Pollutant Emitted	2. Primary Control Device Code	3. Secondary Control Device Code	4. Pollutant Regulatory Code
NOX	024, 065	028	EL
CO	024		EL
VOC			EL
SO2			EL
PM			EL
PM10			EL

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

Potential/Fugitive Emissions

1. Pollutant Emitted: NOX

2. Total Percent Efficiency of Control:

3. Potential Emissions:
Natural Gas Firing 86 lb/hr 376.48 tons/year
Fuel Oil Firing 310 lb/hr 111.60 tons/year

4. Synthetically Limited? [ ]

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

6. Emission Factor:
Reference: Condition #24 B of Permit PSD-FL-254

7. Emissions Method Code:
0

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

Potential Annual Emissions: (Intermittent Simple Cycle Operation)
Natural Gas Firing:
86 lb/hr x 8,760 hrs/yr x 1/ 2,000 tons/lb = 376 tons/yr
Fuel Oil Firing
310 lb/hr x 720 hrs/yr x 1 /2,000 tons/lb = 111.60 tons/yr

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

Allowable Emissions Allowable Emissions ___1___ of ___7___

1. Basis for Allowable Emissions Code:
OTHER

2. Future Effective Date of Allowable Emissions: N/A

3. Requested Allowable Emissions and Units:
3.5 ppmvd (at 15% O2) for Natural Gas
(combined cycle operation for natural gas)

4. Equivalent Allowable Emissions:
26 lb/hour 113.88 tons/year

5. Method of Compliance (limit to 60 characters):
Record keeping
Stack Testing
CEMS

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): KUA respectfully requests that the 3-hour averaging time be changed to a 24-hour averaging period based on the following discussion: NOx emissions are regulated under the PSD program because of the annual nitrogen dioxide standard and because NOx is a precursor to ozone, which is not a short-term but rather a longer-term issue. In fact, the NSPS standards typically establish a 30-day rolling average period for NOx as does Section 403.0872(13)(b), Florida Statues, which provides that for emission units subject to continuous monitoring requirements of the Acid Rain Program (as these units are), compliance with NOx limits shall be demonstrated based on a 30-day rolling average. In addition, Unit #3 will be an intermediate load unit and subject to load changing conditions on a routine basis, therefore the 24-hour averaging period is needed to ensure continuous compliance with the emission limit. 3.5 ppmvd (at 15% O_2) for natural gas requirement to be demonstrated by initial stack test per Permit Condition #24A in PSD –FL-254 (PA98-38).

7

Allowable Emissions Allowable Emissions ___2___ of ___7___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: N/A
3. Requested Allowable Emissions and Units: 15 ppmvd (at 15% O_2) for Fuel Oil (combined cycle operation for fuel oil)	4. Equivalent Allowable Emissions: 108 lb/hour 38.88 tons/year
5. Method of Compliance (limit to 60 characters) Record keeping Stack Testing CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): KUA respectfully requests that the 3-hour averaging time be changed to a 24-hour averaging period based on the following discussion: NOx emissions are regulated under the PSD program because of the annual nitrogen dioxide standard and because NOx is a precursor to ozone, which is not a short-term but rather a longer-term issue. In fact, the NSPS standards typically establish a 30-day rolling average period for NOx as does Section 403.0872(13)(b), Florida Statues, which provides that for emission units subject to continuous monitoring requirements of the Acid Rain Program (as these units are), compliance with NOx limits shall be demonstrated based on a 30-day rolling average. In addition, Unit #3 will be an intermediate load unit and subject to load changing conditions on a routine basis, therefore the 24-hour averaging period is needed to ensure continuous compliance with the emission limit. 15 ppmvd (at 15% O_2 fuel oil) requirement to be demonstrated by initial stack test per Permit Condition #24A in PSD-FL-254 (PA98-38). Fuel oil usage limited to 720 hours per year.	

7

Allowable Emissions Allowable Emissions ___3___ of ___7___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: N/A
3. Requested Allowable Emissions and Units: 9 ppmvd (at 15% O2) for Natural Gas (continuous simple cycle operation)	4. Equivalent Allowable Emissions: 65 lb/hour 284.70 tons/year
5. Method of Compliance (limit to 60 characters): Record keeping Stack Testing CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 9 ppmvd (at 15% O2 for Natural Gas) is ISO condition requirement per Permit Condition #24C in PSD-FL-254 (PA98-38).	

Allowable Emissions Allowable Emissions ___4___ of ___7___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: N/A
3. Requested Allowable Emissions and Units: 42 ppmvd (at 15% O2) for Fuel Oil (continuous simple cycle operation)	4. Equivalent Allowable Emissions: 310 lb/hour 111.60 tons/year
5. Method of Compliance (limit to 60 characters) Record keeping Stack Testing CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 42 ppmvd (at 15% O2 for fuel oil) is ISO condition requirement per condition #24C in PSD-FL-254 (PA98-38). Fuel oil usage limited to 720 hours per year.	

<u>**Allowable Emissions**</u> Allowable Emissions ___5___ of ___7___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: N/A
3. Requested Allowable Emissions and Units: 12 ppmvd (at 15% O2) for Natural Gas (intermittent simple cycle operation)	4. Equivalent Allowable Emissions: 86 lb/hour 376 tons/year
5. Method of Compliance (limit to 60 characters): Record keeping Stack Testing CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 12 ppmvd (at 15% O2 for Natural Gas) is ISO condition requirement per Permit Condition #24B in PSD-FL-254 (PA98-38).	

<u>**Allowable Emissions**</u> Allowable Emissions ___6___ of ___7___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions: N/A
3. Requested Allowable Emissions and Units: 42 ppmvd (at 15% O2) for Fuel Oil (intermittent simple cycle operation)	4. Equivalent Allowable Emissions: 310 lb/hour 111.60 tons/year
5. Method of Compliance (limit to 60 characters) Record keeping Stack Testing CEMS	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 42 ppmvd (at 15% O2 for fuel oil) is ISO condition requirement per Permit Condition #24B in PSD-FL-254 (PA98-38). Fuel oil usage limited to 720 hours per year.	

Allowable Emissions Allowable Emissions ___7___ of ___7___

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Requested Allowable Emissions and Units: 75 ppmvd (at 15% O2)	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year

5. Method of Compliance (limit to 60 characters) - NSPS 40 CFR 60.334(b) Subpart GG
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Rule: 40 CFR 60.334(b) Subpart GG-Standards of Performance for Stationary Gas Turbines. Note: the 75 ppm at 15% O2 is based on an equation in 40 CFR 60.332(a)(1).

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

Potential/Fugitive Emissions

1. Pollutant Emitted: CO	2. Total Percent Efficiency of Control:
3. Potential Emissions: Natural Gas Firing: 71 lb/hour 310.98 tons/year Fuel Oil Firing 108 lb/hour 38.88 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Condition #25 of Permit No. PSD-FL-254	7. Emissions Method Code: 0
8. Calculation of Emissions (limit to 600 characters): Potential Emissions: Natural Gas Firing: 71 lb/hr x 8,760 hrs/yr x 1/2,000 tons/lb = 310.98 tons/yr (Natural Gas Firing, combined cycle with duct burner) Fuel Oil Firing: 108 lb/hr x 720 hrs/yr x 1 /2,000 tons/lb = 38.88 tons/yr (Fuel Oil Firing, combined cycle with duct burner)	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): - 20 ppm Natural Gas Firing, combined cycle with duct burner - 30 ppm Fuel Oil Firing, combined cycle with duct burner - Fuel Oil usage limited to 720 hours per year.	

Allowable Emissions Allowable Emissions ____1__ of ____4

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 12 ppm natural gas burning with duct burner off	4. Equivalent Allowable Emissions: 43 lb/hour 188.34 tons/year
5. Method of Compliance (limit to 60 characters): Record keeping Stack Testing	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 12 ppm; (Natural Gas Firing, simple cycle or combined cycle operation without duct burner) Per Permit Condition #25 in PSD-FL-254 (PA98-38).	

Allowable Emissions Allowable Emissions ____2__ of ___4__

<table>
<tr><td>1. Basis for Allowable Emissions Code:
OTHER</td><td>2. Future Effective Date of Allowable Emissions:</td></tr>
<tr><td>3. Requested Allowable Emissions and Units:
20 ppm fuel oil burning with duct burner off</td><td>4. Equivalent Allowable Emissions:
71 lb/hour 25.56 tons/year</td></tr>
<tr><td colspan="2">5. Method of Compliance (limit to 60 characters):
Record keeping
Stack Testing</td></tr>
<tr><td colspan="2">6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters):
20 ppm; (Fuel Oil Firing, simple cycle or combined cycle operation without duct burner) Per Permit Condition #25 in PSD-FL-254 (PA98-38).
- Fuel oil use limited to 720 hours per year</td></tr>
</table>

Allowable Emissions Allowable Emissions ____3__ of ____4__

<table>
<tr><td>1. Basis for Allowable Emissions Code:
OTHER</td><td>2. Future Effective Date of Allowable Emissions:</td></tr>
<tr><td>3. Requested Allowable Emissions and Units:
20 ppm natural gas burning with duct burner on.</td><td>4. Equivalent Allowable Emissions:
71 lb/hour 310.98 tons/year</td></tr>
<tr><td colspan="2">5. Method of Compliance (limit to 60 characters):
Record keeping
Stack Testing</td></tr>
<tr><td colspan="2">6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters):
20 ppm; (Natural Gas Firing, simple cycle or combined cycle operation with duct burner) Per Permit Condition #25 in PSD-FL-254 (PA98-38).</td></tr>
</table>

Allowable Emissions Allowable Emissions ____4__ of ____4__

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 30 ppm fuel oil burning with duct burner on.	4. Equivalent Allowable Emissions: 108 lb/hour 38.88 tons/year

5. Method of Compliance (limit to 60 characters):
Record keeping
Stack Testing

6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters):
20 ppm; (Natural Gas Firing, simple cycle or combined cycle operation with duct burner)
Per Permit Condition #25 in PSD-FL-254 (PA98-38).

- Fuel oil use limited to 720 hours per year

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

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: 8.5 lb/hour 37.23 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Condition #26 of Permit No. PSD-FL-254	7. Emissions Method Code: 0

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

Potential Emissions:
Natural Gas Firing: 8.5 lb/hr x 8,760 hrs/yr x 1/2,000 tons/lb = 37.23 tons/yr
(Natural Gas Firing, combined cycle with duct burner)
Fuel Oil Firing: 21.4 lb/hr x 720 hrs/yr x 1/ 2,000 tons/lb = 7.70 tons/yr
(Fuel Oil Firing, combined cycle with duct burner)

9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters):
- 4 ppm Natural Gas Firing, combined cycle with duct burner
- 10 ppm Fuel Oil Firing, combined cycle with duct burner
- Fuel Oil usage limited to 720 hours per year

Allowable Emissions Allowable Emissions ___1___ of ___4___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
2. Requested Allowable Emissions and Units: 1.4 ppm natural gas firing with duct burner off.	4. Equivalent Allowable Emissions: 3 lb/hour 13.14 tons/year

5. Method of Compliance (limit to 60 characters):
Record keeping
Initial Stack Testing

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):
1.4 ppm; (Natural Gas Firing, simple cycle or combined cycle operation without duct burner), Per Permit Condition #26 in PSD-FL-254 (PA98-38).

Allowable Emissions Allowable Emissions ___2___ of ___4___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 10 ppm fuel oil burning with duct burner off.	4. Equivalent Allowable Emissions: 21.4 lb/hour 7.7 tons/year
5. Method of Compliance (limit to 60 characters): Record keeping Initial Stack Testing	
6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters): 10 ppm; (Fuel Oil Firing, simple cycle or combined cycle operation without duct burner), Per Permit Condition #26 in PSD-FL-254 (PA98-38). Fuel oil use limited to 720 hours per year	

Allowable Emissions Allowable Emissions ___3___ of ___4___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
4. Requested Allowable Emissions and Units: 4 ppm natural gas firing with duct burner on.	4. Equivalent Allowable Emissions: 8.5 lb/hour 37.23 tons/year
5. Method of Compliance (limit to 60 characters): Record keeping Initial Stack Testing	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): 4 ppm; (Natural Gas Firing, simple cycle or combined cycle operation with duct burner), Per Permit Condition #26 in PSD-FL-254 (PA98-38).	

Allowable Emissions Allowable Emissions ___4___ of ___4___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 10 ppm fuel oil burning with duct burner off.	4. Equivalent Allowable Emissions: 21.4 lb/hour 7.7 tons/year

5. Method of Compliance (limit to 60 characters): Record keeping Initial Stack Testing
6. Allowable Emissions Comment (Desc. Of Operating Method) (limit to 200 characters): 10 ppm; (Fuel Oil Firing, simple cycle or combined cycle operation with duct burner), Per Permit Condition #26 in PSD-FL-254 (PA98-38). Fuel oil use limited to 720 hours per year

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

Potential/Fugitive Emissions

1. Pollutant Emitted: SO2	2. Total Percent Efficiency of Control:	
3. Potential Emissions: Fuel Oil Firing: 105.8 lb/hr 38.1 tons/year		4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year		
6. Emission Factor: Reference: Condition #27 of Permit No. PSD-FL-254 (PA98-38)		7. Emissions Method Code: 2
8. Calculation of Emissions (limit to 600 characters): Potential Emissions: Fuel Oil Firing: 105.8 lbs/hr x 720 hrs/yr x 1/2,000 tons/lb = 38.1 tons/yr		
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): SO2 emissions limited by firing pipeline natural gas (sulfur content less than 20 grains per 100 standard cubic foot) or by firing No.2 distillate fuel oil with a maximum 0.05 percent sulfur for 720 hours per year.		

Allowable Emissions Allowable Emissions ___1___ of ___3___

1. Basis for Allowable Emissions Code: ESCPSD	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: < 20 gr/100 scf for Natural Gas	4. Equivalent Allowable Emissions: N/A lb/hour 38.1 tons/year
5. Method of Compliance (limit to 60 characters): Firing of pipeline natural gas Natural gas monitoring schedule, Condition #48 of Permit No. PSD-FL-254 (PA98-38) Record keeping	

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Pipeline natural gas (sulfur content less than 20 grains per 100 standard cubic feet)

Allowable Emissions Allowable Emissions ___2___ of ___3___

1. Basis for Allowable Emissions Code: ESCPSD	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: Maximum 0.05% sulfur content for Fuel Oil	4. Equivalent Allowable Emissions: N/A lb/hour 38.1 tons/year
5. Method of Compliance (limit to 60 characters): Firing of 0.05% sulfur oil Fuel Oil monitoring schedule, Condition #49 of Permit No. PSD-FL-254 (PA98-38) Record keeping	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Firing of 0.05% sulfur content Fuel Oil Fuel oil usage limited to 720 hours per year	

Allowable Emissions Allowable Emissions ___3___ of ___3___

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: Maximum 0.8 % Sulfur fuel oil content	4. Equivalent Allowable Emissions:
5. Method of Compliance (limit to 60 characters): Rule: 40 CFR 60.333 Subpart GG	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): Rule: 40 CFR 60.333, Subpart GG-Standards of Performance for Stationary Gas Turbines	

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

Potential/Fugitive Emissions

1. Pollutant Emitted: PM/PM10	2. Total Percent Efficiency of Control:
3. Potential Emissions: 18 lb/hour 78.84 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: Based on Vendor Data	7. Emissions Method Code: 2

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

Potential Emissions
Natural Gas Firing:
18 lbs/hr x 8,760 hrs/yr x 1/2,000 tons/lb = 78.84 tons/yr
Fuel Oil Firing:
102 lbs/hr x 720 hrs/yr x 1/2,000 tons/lb = 36.72 tons/yr

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

Allowable Emissions Allowable Emissions ___1___ of ___1___

1. Basis for Allowable Emissions Code: OTHER	2. Future Effective Date of Allowable Emissions:
3. Requested Allowable Emissions and Units: 10% Opacity	4. Equivalent Allowable Emissions: N/A lb/hour N/A tons/year

5. Method of Compliance (limit to 60 characters):
Record keeping
Fuel Monitoring Schedule
VE Limitation as a surrogate for PM/PM10 emissions

6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters):
PM/PM10 emissions from the combustion turbine operating with or without the duct burner shall not exceed 10 percent opacity, per Permit Condition #28 of Permit No. PSD-FL-254 (PA98-38).

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

Visible Emissions Limitation: Visible Emissions Limitation ___1___ of __1____

1. Visible Emissions Subtype: VE10	2. Basis for Allowable Opacity: [ ] Rule [X] Other
3. Requested Allowable Opacity: Normal Conditions: 10 % Exceptional Conditions: 10 % Maximum Period of Excess Opacity Allowed: 6 min/hour	
4. Method of Compliance: Stack Testing	
5. Visible Emissions Comment (limit to 200 characters): 10 percent opacity limit is specified in Condition #28 of Permit No. PSD-FL-254	

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

Continuous Monitoring System: Continuous Monitor __1__ of ___2__

1. Parameter Code: EM	2. Pollutant(s): NOX
3. CMS Requirement: 40 CFR 75	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: TECO Model Number: 42C	Serial Number: 42C-67177-356
5. Installation Date: 04/01/2001	6. Performance Specification Test Date: 05/10/2001
7. Continuous Monitor Comment (limit to 200 characters): CEMS QA Plan in Attachment C Used for compliance CAM not required.	

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

Continuous Monitoring System: Continuous Monitor __2___ of __2__

1. Parameter Code: O2	2. Pollutant(s):
3. CMS Requirement: 40 CFR 75	[X] Rule [ ] Other
4. Monitor Information: Manufacturer: Servomex Model Number: 1440	Serial Number: 01420C11628
5. Installation Date: 04/01/2001	6. Performance Specification Test Date: 05/10/2001
7. Continuous Monitor Comment (limit to 200 characters): CEMS QA Plan in Attachment C	

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

Supplemental Requirements

1. Process Flow Diagram [ ] Attached, Document ID:________ [ ] Not Applicable [X] Waiver Requested
2. Fuel Analysis or Specification [X] Attached, Document ID: Attachment E [ ] Not Applicable [ ] Waiver Requested
3. Detailed Description of Control Equipment [X] Attached, Document ID: Attachment F [ ] Not Applicable [ ] Waiver Requested
4. Description of Stack Sampling Facilities [X] Attached, Document ID: Attachment G [ ] Not Applicable [ ] Waiver Requested
5. Compliance Test Report [X] Attached, Document ID: Attachment H [ ] Previously submitted, Date:_______________ [ ] Not Applicable
6. Procedures for Startup and Shutdown [X] Attached, Document ID: Attachment I [ ] Not Applicable [ ] Waiver Requested

7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID:________ [X] Not Applicable
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [X] Not Applicable
10. Supplemental Requirements Comment: A waiver is requested for Supplemental Requirement 1, as this item was not altered as a result of this application and have previously been submitted within the last 5 years in the following permit applications: Air Construction Permit PSD-FL-254, application of August 5, 1998 and Site Certification Application.

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [X] Attached, Document ID: Attachment J [ ] Not Applicable	
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:________ [X] Not Applicable	
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:________ [X] Not Applicable	
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:________ [X] Not Applicable	Discussion w/ TO unf... OK
15. Acid Rain Part Application (Hard-copy Required) [X] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID: Attachment K [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a)1.) Attached, Document ID:________ [ ] New Unit Exemption (Form No. 62-210.900(1)(a)2.) Attached, Document ID:________ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a)3.) Attached, Document ID:________ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a)4.) Attached, Document ID:________ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:________ [ ] Not Applicable	

III. EMISSIONS UNIT INFORMATION 004

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

A. GENERAL EMISSIONS UNIT INFORMATION
(All Emissions Units)

Emissions Unit Description and Status

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

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

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

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

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

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

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

3. Description of Emissions Unit Addressed in This Section (limit to 60 characters): One Million Gallon Distillate Fuel Oil Storage Tank

4. Emissions Unit Identification Number: ID: 004 | [ ] No ID | [ ] ID Unknown

5. Emissions Unit Status Code: A	6. Initial Startup Date: 05/01/2001	7. Emissions Unit Major Group SIC Code: 49	8. Acid Rain Unit? [ ]

9. Emissions Unit Comment: (Limit to 500 Characters) The No.2 distillate fuel oil storage tank (1,000,000 gal) is reported as an emission unit because it is subject to reporting regulations based on the emissions guidelines of the New Source Performance Standards 40 CFR 60, Subpart Kb.
The tank is a vertical fixed roof design

Emissions Unit Control Equipment

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

Emissions Unit Details

1. Package Unit: One million gallon distillate fuel oil storage tank Manufacturer:	Model Number:	
2. Generator Nameplate Rating:		
3. Incinerator Information:		
Dwell Temperature:		°F
Dwell Time:		seconds
Incinerator Afterburner Temperature:		°F

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

Emissions Unit Operating Capacity and Schedule

1. Maximum Heat Input Rate:		mmBtu/hr
2. Maximum Incineration Rate:	lb/hr	tons/day
3. Maximum Process or Throughput Rate: 10,496 thousand gal/yr		
4. Maximum Production Rate:		
5. Requested Maximum Operating Schedule:	24 hours/day 52 weeks/year	7 days/week 8,760 hours/year
7. Operating Capacity/Schedule Comment (limit to 200 characters): The maximum throughput rate corresponds to the use of No.2 fuel oil for 720 hours		

C. EMISSIONS UNIT REGULATIONS
(Regulated Emissions Units Only)

List of Applicable Regulations

40 CFR 60, Subpart A – General Provisions	Emission unit applicable regulations hereby incorporates by reference the Title V Core List of Applicable Regulations that all Title V sources are presumptively subject.
40 CFR 60, Subpart Kb	
40 CFR 60.116b, Monitoring of Operations	
62-204.800 Standards of Performance for Volatile Organic Liquid Storage Vessels	

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

Emission Point Description and Type

1. Identification of Point on Plot Plan or Flow Diagram? ID# on Plot Plan in Attachment A	2. Emission Point Type Code: 1

3. Descriptions of Emission Points Comprising this Emissions Unit for VE Tracking (limit to 100 characters per point): N/A
4. ID Numbers or Descriptions of Emission Units with this Emission Point in Common: The emission point for a vertical fixed roof storage tank is the breather valve on the dome roof. There 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 expulsion of vapor from a tank through vapor expansion and contraction, which are the result of changes in ambient temperature and barometric pressure. (Also know as standing loss) 2) Working Loss: Emissions resulting from the filling and emptying of the storage tanks which are associated with the change in liquid level within the tank.

5. Discharge Type Code: P	6. Stack Height: N/A feet	7. Exit Diameter: N/A feet
8. Exit Temperature: Ambient °F	9. Actual Volumetric Flow Rate: N/A acfm	10. Water Vapor: N/A %

11. Maximum Dry Standard Flow Rate: N/A dscfm	12. Nonstack Emission Point Height: 35 feet

13. Emission Point UTM Coordinates: Zone: 17 East (km): 447.743 North (km): 3127.475
14. Emission Point Comment (limit to 200 characters): This emission point for a fixed roof storage tank is the breather valve on the dome roof.

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

Segment Description and Rate: Segment ___1__ of ___2__

2. Segment Description (Process/Fuel Type) (limit to 500 characters): Breathing 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.		
2. Source Classification Code (SCC): 40301019	3. SCC Units: Thousand Gallons Stored	
4. Maximum Hourly Rate: N/A	5. Maximum Annual Rate: N/A	6. Estimated Annual Activity Factor: 1,000
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A
12. Segment Comment (limit to 200 characters): (1,000,000 gal stored)/(1,000 gal) = 1,000 capacity factor		

Segment Description and Rate: Segment ___2__ of __2___

1. Segment Description (Process/Fuel Type) (limit to 500 characters): Working Loss: Emissions resulting from the filling and emptying of the storage tank which are associated with the change in the liquid level within the tank.		
2. Source Classification Code (SCC): 40301021	3. SCC Units: Thousand Gallons Transferred or Handled	
4. Maximum Hourly Rate: N/A	5. Maximum Annual Rate: N/A	6. Estimated Annual Activity Factor: 10,496.00
7. Maximum % Sulfur: N/A	8. Maximum % Ash: N/A	9. Million Btu per SCC Unit: N/A

13. Segment Comment (limit to 200 characters):

F. EMISSIONS UNIT POLLUTANTS
(All Emissions Units)

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

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

Potential/Fugitive Emissions

1. Pollutant Emitted: VOC	2. Total Percent Efficiency of Control:
3. Potential Emissions: lb/hour 0.32 tons/year	4. Synthetically Limited? [ ]
5. Range of Estimated Fugitive Emissions: [ ] 1 [ ] 2 [ ] 3 ______ to ______ tons/year	
6. Emission Factor: Reference: EPA TANKS Program 3.1	7. Emissions Method Code: 3
8. Calculation of Emissions (limit to 600 characters): Emission calculations are based on USEPA's TANKS Version 3.1 Program, which include both breathing and working loss emissions.	
9. Pollutant Potential/Fugitive Emissions Comment (limit to 200 characters): Maximum estimated emissions based on No.2 distillate fuel oil firing for 720 hours/year.	

Allowable Emissions Allowable Emissions ___1___ of ___1___

1. Basis for Allowable Emissions Code: RULE	2. Future Effective Date of Allowable Emissions: N/A
3. Requested Allowable Emissions and Units: N/A	4. Equivalent Allowable Emissions: N/A
5. Method of Compliance (limit to 60 characters): As specified in 40 CFR 60.116 (a) and (b), Subpart Kb	
6. Allowable Emissions Comment (Desc. of Operating Method) (limit to 200 characters): RULE: 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.	

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

Visible Emissions Limitation: Visible Emissions Limitation ______ of ______

1. Visible Emissions Subtype: N/A	2. Basis for Allowable Opacity: [ ] Rule [ ] Other
3. Requested Allowable Opacity: Normal Conditions: % Exceptional Conditions: % Maximum Period of Excess Opacity Allowed: min/hour	
4. Method of Compliance:	
6. Visible Emissions Comment (limit to 200 characters):	

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

Continuous Monitoring System: Continuous Monitor _____ of _____

1. Parameter Code: N/A	2. Pollutant(s):
3. CMS Requirement:	[ ] Rule [X] Other
4. Monitor Information: Manufacturer: Model Number:	Serial Number:
5. Installation Date:	6. Performance Specification Test Date:
7. Continuous Monitor Comment (limit to 200 characters):	

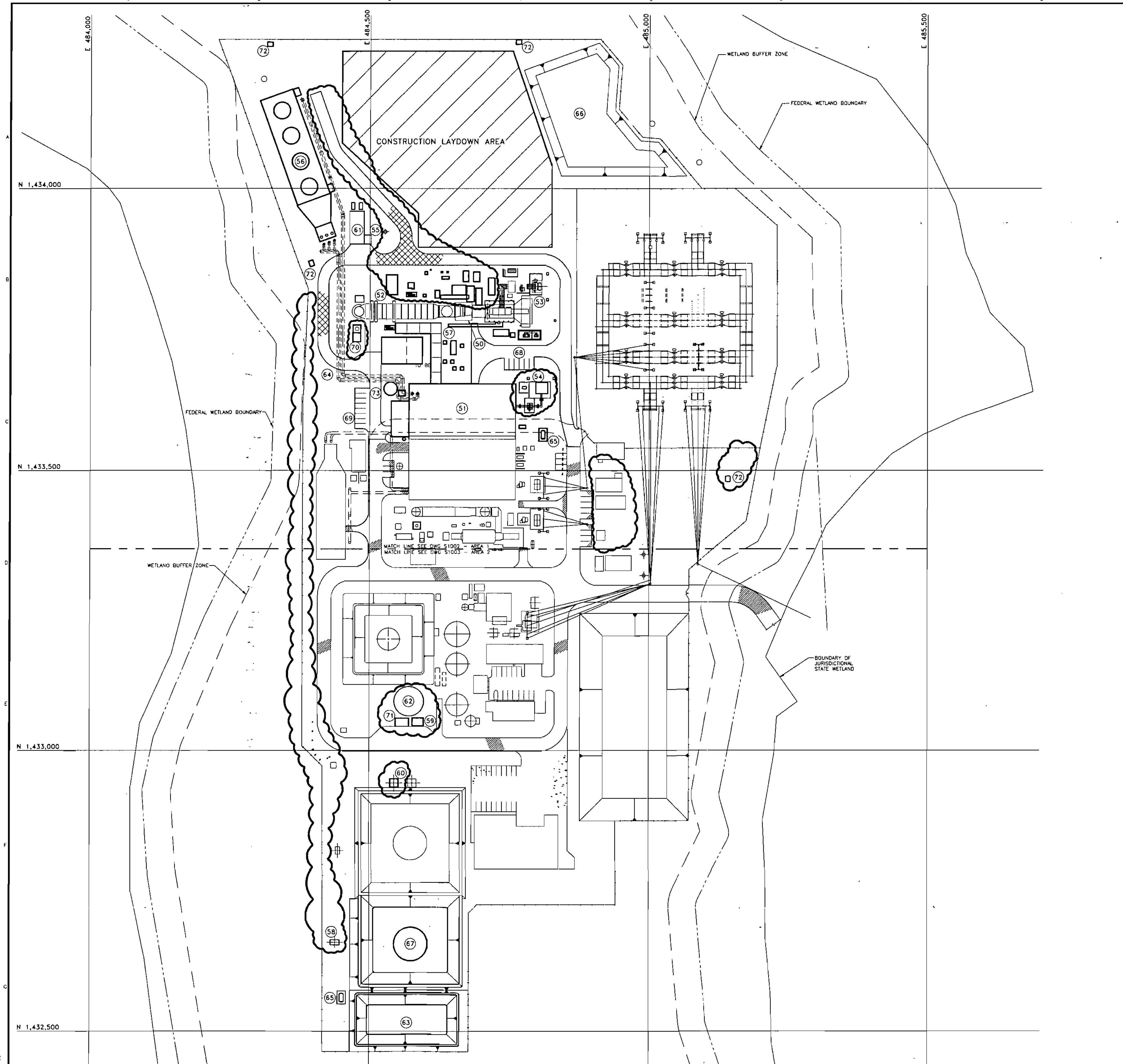
J. EMISSIONS UNIT SUPPLEMENTAL INFORMATION
(Regulated Emissions Units Only)

Supplemental Requirements

1. Process Flow Diagram [ ] Attached, Document ID:________ [ ] Not Applicable [X] Waiver Requested	
2. Fuel Analysis or Specification [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested	
3. Detailed Description of Control Equipment [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested	
4. Description of Stack Sampling Facilities [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested	
5. Compliance Test Report [ ] Attached, Document ID:________ [ ] Previously submitted, Date:________________ [X] Not Applicable	
6. Procedures for Startup and Shutdown [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested	
7. Operation and Maintenance Plan [ ] Attached, Document ID:________ [X] Not Applicable [ ] Waiver Requested	
8. Supplemental Information for Construction Permit Application [ ] Attached, Document ID:________ [X] Not Applicable	
9. Other Information Required by Rule or Statute [ ] Attached, Document ID:________ [X] Not Applicable	
10. Supplemental Requirements Comment: A waiver is requested for Supplemental Requirement 1, as this item was not altered as a result of this application and have previously been submitted within the last 5 years in the following permit applications: Air Construction Permit PSD-FL-254, application of August 5, 1998 and Site Certification Application.	

Additional Supplemental Requirements for Title V Air Operation Permit Applications

11. Alternative Methods of Operation [ ] Attached, Document ID:_______ [X] Not Applicable	
12. Alternative Modes of Operation (Emissions Trading) [ ] Attached, Document ID:_______ [X] Not Applicable	
13. Identification of Additional Applicable Requirements [ ] Attached, Document ID:_______ [X] Not Applicable	
14. Compliance Assurance Monitoring Plan [ ] Attached, Document ID:_______ [X] Not Applicable	
15. Acid Rain Part Application (Hard-copy Required) [ ] Acid Rain Part - Phase II (Form No. 62-210.900(1)(a)) Attached, Document ID:_______ [ ] Repowering Extension Plan (Form No. 62-210.900(1)(a) 1.) Attached, Document ID:_______ [ ] New Unit Exemption (Form No. 62-210.900(1)(a) 2.) Attached, Document ID:_______ [ ] Retired Unit Exemption (Form No. 62-210.900(1)(a) 3.) Attached, Document ID:_______ [ ] Phase II NOx Compliance Plan (Form No. 62-210.900(1)(a) 4.) Attached, Document ID:_______ [ ] Phase NOx Averaging Plan (Form No. 62-210.900(1)(a)5.) Attached, Document ID:_______ [X] Not Applicable	



UNIT 3 LEGEND

- (50) COMBUSTION TURBINE GENERATOR AND AUXILIARIES
- (51) STEAM TURBINE GENERATOR AND AUXILIARIES
- (52) HEAT RECOVERY STEAM GENERATOR
- (53) CT GENERATOR STEPUP TRANSFORMER
- (54) ST GENERATOR STEPUP TRANSFORMER
- (55) CW ACID STORAGE TANK AREA
- (56) COOLING TOWER
- (57) PIPE RACK
- (58) FUEL OIL FORWARDING SKID
- (59) DEMIN WATER TRANSFER PUMPS
- (60) FOAM HOUSE
- (61) CW CHEM FEED BUILDING
- (62) DEMINERALIZED WATER STORAGE TANK
- (63) EXPANDED PERCOLATION POND
- (64) CIRCULATING WATER LINES
- (65) OIL/WATER SEPARATOR
- (66) STORM WATER POND
- (67) FUEL OIL STORAGE TANK
- (68) COVERED PARKING
- (69) PARKING
- (70) WASTE PUMP/BOILER BLOWDOWN TANK
- (71) FUEL OIL UNLOADING PUMPS
- (72) WATER WELL PUMPS
- (73) CONDENSATE STORAGE TANK

NEW FENCE

-INDICATES NEW ASPHALT SURFACING

-INDICATES EXISTING ASPHALT SURFACING

-INDICATES NEW AGGRAGATE SURFACING

-INDICATES EXISTING CONCRETE

NOTES

1. FOR LOCATION OF STRUCTURES AND YARD EQUIPMENT SEE DRAWINGS S1002 AND S1003.

APPROVED FOR CONSTRUCTION

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
3	2/25/2000	ISSUED FOR REFERENCE - CONTRACT 72.0201	LLF	LLF	PCG	PCG	SMG
2	10/29/1999	APPROVED FOR CONSTRUCTION-SPEC 71.0201	LLF	PLN	LJK	PCG	SMG
1	8/27/1999	ISSUED FOR BIDS	LLF	PLN		PCG	SMG
0	8/27/1999	ISSUED FOR PERMITS	LLF	PLN		PCG	SMG

N

60' 30' 0 60' 120'
SCALE: 1"=60'

BLACK & VEATCH
ENGINEER PLN
DRAWN LLF
CHECKED LJK
DATE 10/29/1999

KISSIMMEE UTILITY AUTHORITY
CANE ISLAND PLANT - UNIT 3
OVERALL PROPERTY ARRANGEMENT

PROJECT 60818-CSTU-S1001 DRAWING NUMBER
REV 3
CODE
AREA

Attachment A

Attachment B
List of Proposed Insignificant Activities

1. Natural Gas Fuel Gas Heater
2. Emission Unit 006, Cooling Tower

UNREGULATED.

BLACK & VEATCH

21 West Church Street, Tower 10
Jacksonville, FL 32202-3139 USA

Tel: (904) 665-4448
Fax: (904) 665-5234

Black & Veatch Corporation

Kissimmee Utility Authority
Cane Island Unit 3

B&V Project 65270
B&V File 32.0465
B&V Letter No.: BV/DEP – L001
July 17, 2001

Florida Department of Environmental Protection
Division of Air Resources Management
2600 Blair Stone Road
Tallahassee, Florida 32399

Subject: Fuel Gas Heater Air Permitting Applicability

Attention: Teresa Heron
Air Permit Engineer

Dear Ms. Heron:

As we discussed during our telephone conversation on Thursday, July 12, 2001, the purpose of this letter is to request the DEP's review and concurrence of the regulatory and air permitting applicability of a natural gas fired, 3.5 mmBtu/hr fuel gas heater installed at KUA's Cane Island Power Park as part of the Unit 3 combined cycle combustion turbine project. The fuel gas heater unit was identified during an emission unit inventory conducted in preparation for the Title V Air Operating Permit Revision Application for Unit 3.

Based on our initial regulatory analysis of the fuel gas heater, we have concluded the fuel gas heater does not require an air construction permit, and for purposes of the Title V Air Operating Permit, meets the requirements of an insignificant air emissions source. The following information is provided for your consideration regarding the fuel gas heater and the relevant air permitting regulations.

Air Construction Permit Requirements

The fuel gas heater is an indirect, water-bath, gas fired heater, utilizing hot water as heat transfer medium to raise the temperature of the natural gas prior to it entering the combustion turbine. A review of applicable regulatory requirements indicates that an air construction permit is not required for the natural gas fired fuel gas heater. This conclusion is based on our interpretation of Rule 62-210.300 Permits Required, Part (3) Exemptions, Subpart (a)(3) Categorical Exemptions, which states:

> *"One or more fossil fuel steam generators and hot water generating units located within a single facility, collectively having a total rated heat input equaling 10 million BTU per hour or less, and firing exclusively by natural gas or propane, provided:*
>
> *a. During periods of natural gas curtailment, only propane or fuel oil containing no more than 1.0 percent sulfur is fired; and*

b. *None of the generators or hot water heating units is subject to the Federal Acid Rain program."*

The natural gas fired fuel gas heater is considered a hot water generating unit with a heat input of less than 10 mmBtu/hr, and is therefore categorically exempt from having to obtain an air construction permit.

Title V Air Operating Permit Requirements

Considering Title V operating permit requirements, Rule 62-210.300 Permits Required, Part (3) Exemptions states that *"Emissions units and pollutant-emitting activities exempt from permitting under this rule shall not be exempt from the permitting requirements of Chapter 62-213* [Title V Air Operating Permits], *if they are contained within a Title V source; however, such emissions units and activities shall be considered insignificant for Title V purposes provided they meet the criteria of Rule 62-213.430(6)(b). Likewise, no proposed new emissions unit or activity that would be considered insignificant for Title V purposes shall be required to obtain an air construction permit".* Referring to Rule 62-213.430(6)(b), an emission unit or activity shall be considered insignificant for Title V purposed if all of the following criteria are met:

1. *Such unit or activity would be subject to no unit-specific applicable requirement.*
2. *Such unit or activity, in combination with other units and activities proposed as insignificant, would not cause the facility to exceed any major source threshold(s).*
3. *Such unit or activity would neither emit or have the potential to emit:*

a. *500 pounds per year or more of lead and lead compounds expressed as lead*
b. *1,000 pounds per year or more of any hazardous air pollutant*
c. *2,500 pounds per year or more of total hazardous air pollutants, or*
d. *5.0 tons per year or more of any other regulated pollutant.*

In addressing the above Item 1, a review of Chapter 62-296 Stationary Sources-Emission Standards found no specific emission standard for fuel gas heaters (or water heaters), and the unit is not subject to New Source Performance Standards (NSPS) as further discussed below. Regarding Item 2, emission calculations were performed utilizing AP-42 emission factors. The calculations indicated that lead was less than the 500-pound threshold, hazardous air pollutants were less than the thresholds, and no other regulated pollutant approached the 5.0-ton per year limit. Therefore, the fuel gas heater is considered an "insignificant source" for Title V purposes.

New Source Performance Standards (NSPS) Subpart Dc

The requirements of NSPS Subpart Dc are applicable to steam generating units with a maximum design heat input greater than 10 mmBtu/hr and less than 100 mmBtu/hr. The fuel gas heater maximum design heat input is 3.5 mmBtu/hr, and therefore is not subject to NSPS Subpart Dc requirements.

On behalf of KUA, Black & Veatch respectfully requests, at your earliest convenience, a written reply of concurrence and/or determination of air permitting applicability regarding the fuel gas heater as discussed above. If you have any questions regarding this matter, or need additional information, please do not hesitate to contact me at 904-665-5227.

Very truly yours,

BLACK & VEATCH

Timothy M. Hillman
Air Permitting Manager

TMH:dsy

cc: Ben Sharma, KUA
Larry Mattern, KUA
Ron Utter, B&V
Don Schultz, B&V
Mike Soltys, B&V

Department of
Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

July 18, 2001

Mr. Timothy M. Hillman
Air Permitting Manager
Black & Veatch Corporation
21 West Church Street, Tower 10
Jacksonville, Florida 32202-3139

Re: KUA Cane Island Power Park Fuel Gas Heater
Facility **0970043**

Dear Mr. Hillman:

We have reviewed the documentation on the subject fuel gas heater as described in your letter dated July 16, 2001, and concur with the conclusion that the said heater should be properly identified as an *insignificant activity* in the planned Title V Air Operation Permit Revision Application for the facility.

Sincerely,

Scott M. Sheplak
Scott M. Sheplak, P.E.
Administrator
Title V Section

Cc: Mr. Len Kozlov, Central District Office DEP

Attachment C
Compliance Report and Plan

The new simple cycle turbine generator (emission unit 003) are operating in compliance with Air Construction Permit PSD-FL-254 (PA98-38). The units' initial emission stack tests have been completed and the results have been submitted to the FDEP's Regional Office. Please refer to the following summary tables.

Combined Cycle testing has been scheduled for October 18-19, 2001. Results of testing will be provided to FDEP upon test results report certification.

ACE
AIR CONSULTING
& ENGINEERING, INC.

2106 N.W. 67th Place • Suite 4 • Gainesville, Florida • 32653
(352) 335-1889 FAX (352) 335-1891

REPORT CERTIFICATION

To the best of my knowledge, all applicable field and analytical procedures comply with the Florida Department of Environmental Protection requirements and all test data and plant operating data are true and correct.

SIGNATURE SECURITY SIGNATURE SECURITY

Dagmar Fick, Mechanical Engineer

8/29/2001

Date

2.0 SUMMARY AND DISCUSSION OF RESULTS

CT-3 test results were found to be within the allowable standards of the current permit. Table 1 summarizes the emission results.
Oxides of Nitrogen emissions averaged 8.20 ppmvd @ 15% O_2 and 47.25 lbs/hr, which is within the allowable standard of 9 ppm_vd @ 15% O_2 and 65 lbs/hr. Actual CO emissions at 0.17 ppm_{vd} and 0.5 lbs/hr compare well to the permitted values of 12 ppm_{vd} and 43 lbs/hr. VOC emissions averaged 0.06 ppm_{vd} and 0.270 lbs/hr as propane. SO_2 emissions calculated by fuel analysis averaged 0.27 lbs/hr. The fuel analysis of the natural gas stream showed 0.067 grains of Sulfur per 100cubic feet of gas, which is also within the permitted Sulfur content of 20 grains per 100 cubic foot. SO_2 emission calculations are presented in Appendix F along with the fuel analysis and the production data.

Visible emissions, observed concurrently with each compliance run, averaged 0.0 percent opacity for the highest six-minute period of each run (see Appendix D for VE data). Permitted opacity is 10%.

During the test, the heat input rate of the turbine based on the lower heating value (LHV) averaged 1414.4 million btu per hour (MMBTUH) (see Appendix F for calculations).

Complete emission summaries with data logger records and strip chart copies are presented in Appendix B and C.

Table 1. Emission Summary
Unit 3 Combustion Turbine - Gas Fired
Kissimmee Electric Authority
Intercession City, Florida
July 17, 2001

Run Number	Time	Oxygen %	NOx Emissions ppm	NOx ppm 15% O2	NOx ppm @ISO	NOx lbs/hr	NOx lbs/MMBTU	CO Emissions ppm	CO lbs/hr	CO lbs/MMBTU	C3H8 Emissions as Propane ppm	C3H8 lbs/hr	CT Gas Flow lbs/sec	CT Heat Input MMBTUH HHV	CT Heat Input MMBTUH LHV
Full Load - 160.2 MW															
1	0910-1017	13.87	9.96	8.36	10.64	47.96	0.031	0.29	0.857	0.0006	0.10	0.4720	18.9	1556.7	1408.6
2	1040-1149	13.77	9.91	8.20	10.83	47.08	0.030	0.09	0.259	0.0002	0.03	0.1230	18.5	1558.0	1409.7
3	1208-1317	13.81	9.68	8.05	11.24	46.72	0.030	0.13	0.373	0.0002	0.05	0.2140	18.7	1574.8	1425.0
Average	---	13.82	9.85	8.20	10.90	47.25	0.030	0.17	0.496	0.0003	0.06	0.270	18.7	1563.2	1414.4

Natural Gas Fd-Factor = 8710 MMBTU/dscf
lbs/hr = ppm(2.595 x 10^E-9)MW (20.9/20.9-%O2)(Fd)(Heat Input HHV)
Heat Input HHV = (gas flow)(1041 dry Btu/cf)(3600 sec/hr)/10E6/gas density
MW CO = 28 lbs/lb-mole *MW NOx = 46 lbs/lb-mole* *MW C3H8 = 44.033 lbs/lb-mole*

SO2 Emissions (Subpart GG NSPS) = 0.27 lbs/hr; 0.067 grains/100 cuft per fuel analysis

Allowable Emissions
NOx = 9 ppmvd @ 15%O2 & 65 lbs/hr
CO = 12 ppmvd & 43 lbs/hr
C3H8 = 1.4 ppmvd & 3.0 lbs/hr as VOC
SO2 = 20 grains/100 std. cuft

FACILITY INFORMATION (RT 102)

ORIS Code/Facility ID: 7238 EPA FINDS ID: FL0001937747 EPA AIRS ID: 12-097-00043 State ID:

Plant Name: CANE ISLAND State: FL Latitude: 281640 Longitude: 0813101

County Code: 097 County Name: OSCEOLA Source Category/Type: ELECTRIC UTILITY

Primary SIC Code/Description: 4911 Electric Services

STACKS AND PIPES (RT 503)

Stack/Pipe ID	Stack/Pipe Name	Activation Date	Retirement Date	Bypass Stack	Unit IDs	Stack Exit Height	Stack Base Elevation	Area At Stack Exit	Area At Flow Monitor
MS2A	UNIT 2A	01/01/1995	/ /	B	2	100	68	53	
MS2B	UNIT 2B	01/01/1995	/ /		2	100	68	53	
MS3A	UNIT 3A	04/01/2001	/ /	B	3	100	68	299	
MS3B	UNIT 3B	04/01/2001	/ /		3	130	68	234	

UNIT OPERATION INFORMATION (RT 504)

Unit ID	Unit Short Name	Boiler Type	Max Heat Input(mmBtu)	1st Comm Operation Date	Retirement Date	Stack Exit Height	Stack Base Elevation	Area At Stack Exit	Area At Flow Monitor
**1	UNIT **1	CT	367.0	01/01/1995	/ /	40	68	47	
2	UNIT 2	CC	869.0	01/01/1995	/ /	100	68	53	
3	UNIT 3	CC	1733.0	05/20/2001	/ /	130	68	234	

CODES FOR UNIT OPERATION DATA (RT 504)

Boiler Type Codes: CC - Combined cycle, CT - Combustion turbine

UNIT PROGRAM INFORMATION (RT 505)

Unit ID	Program	Unit Class	Reporting Frequency	Program Participation Date	State Regulation Code	State/Local Regulatory Agency Code
**1	ARP	P2	Q	01/01/1998		FL
2	ARP	P2	Q	01/01/1995		FL
3	ARP	P2	Q	04/01/2001		FL

Unit Class Codes: P2 - Phase II (ARP only)
Reporting Frequency Codes: Q - Quarterly

EIA Cross Reference Information (RT 506)

Unit ID	Part 75 Monitoring Location ID	EIA Boiler ID	EIA Flue ID	EIA Reporting Year	EIA 767 Reporting Indicator	EIA Facility/ORISPL Number
**1	**1				N	
2	2				N	
3	3				N	

FUEL USAGE QUALIFICATION INFORMATION (RT 507)

Capacity or Gas Usage

Unit ID	Year of Qualification	Year1	Year1 Type	Year1%	Year2	Year2 Type	Year2%	Year3	Year3 Type	Year3%	Average%	Type of Qualification	Method of Qualifying
**1	2000	1997	A	99.0%	1998	A	99.0%	1999	A	99.0%	99.0%	GF	3HD
2	2000	1997	A	99.0%	1998	A	99.0%	1999	A	99.0%	99.0%	GF	3HD
3	2001	2001	P	99.0%	2002	P	99.0%	2003	P	99.0%	99.0%	GF	3PR

Gas Qualifying Codes: 3HD - Three years of historical data, 3PR - Three years projected cap. factor or fuel use
Type of Qualification Codes: GF - Gas-Fired Qualification

FACILITY NAME: CANE ISLAND ORIS CODE: 7238

UNIT/STACK/PIPE ID: **1

MONITORING SYSTEMS/ANALYTICAL COMPONENTS (RT 510)

SYSTEM						ANALYTICAL COMPONENTS AND DAHS SOFTWARE						
Status	System ID	Para- meter	P/B	First Reporting Date	Last Reporting Date	Com- ponent ID	Status	Com- ponent Type	Sample Method (SAM)	Manufacturer	Model or Version	Serial #
U	101	NOX	P	01/01/1998	/ /	001	U	NOXA	DIL	TECO	42D	42D-48216-280
						002	U	O2D	DIL	SERROMAX	ZRO	9573837
						006	U	DAHS		KVB-ENERTEC, INC.	FOCUS 2.1	1953000000
U	103	GAS	P	01/01/1998	/ /	003	U	GFFM	VTX	YOKOGAWA	YF105-NN-NA3A	40328007
						006	U	DAHS		KVB-ENERTEC, INC.	FOCUS 2.1	1953000000
U	104	OILV	P	01/01/1998	/ /	004	U	OFFM	TUR	FLOW TECHNOLOGY INC.	FT-20C3XBRLEA-5	2001833
						005	U	OFFM	TUR	FLOW TECHNOLOGY INC.	FT-20C3XBRLEA-5	2001997
						006	U	DAHS		KVB-ENERTEC, INC.	FOCUS 2.1	1953000000

Parameter Monitored Codes: GAS - Gas fuel flow, NOX - NOx emission rate, OILV - Volumetric oil flow
Primary/Backup Codes: P - Primary
Component Type Codes: DAHS - Data acquisition & handling system, GFFM - Gas fuel flowmeter, NOXA - Dual-Range NOx analyzer, O2D - Dry O2 analyzer, OFFM - Oil fuel flow meter
SAM codes: DIL - Dilution, VTX - Vortex, TUR - Turbine
Status Codes: U - Unchanged

UNIT/STACK/PIPE ID: 2

MONITORING SYSTEMS/ANALYTICAL COMPONENTS (RT 510)

SYSTEM						ANALYTICAL COMPONENTS AND DAHS SOFTWARE						
Status	System ID	Parameter	P/B	First Reporting Date	Last Reporting Date	Component ID	Status	Component Type	Sample Method (SAM)	Manufacturer	Model or Version	Serial #
U	203	GAS	P	01/01/1996	/ /	006	U	DAHS		KVB-ENERTEC, INC.	FOCUS 2.1	1953000000
						203	U	GFFM	ORF	ROSEMOUNT	1151	209977
U	204	OILV	P	01/01/1996	/ /	006	U	DAHS		KVB-ENERTEC, INC.	FOCUS 2.1	1953000000
						204	U	OFFM	PDP	GENERAL ELECTRIC	GE 7EA	9312-34846-1-1

Parameter Monitored Codes: GAS - Gas fuel flow, OILV - Volumetric oil flow
Primary/Backup Codes: P - Primary
Component Type Codes: DAHS - Data acquisition & handling system, GFFM - Gas fuel flowmeter, OFFM - Oil fuel flow meter
SAM codes: ORF - Orifice, PDP - Positive displacement
Status Codes: U - Unchanged

UNIT/STACK/PIPE ID: 3

MONITORING SYSTEMS/ANALYTICAL COMPONENTS (RT 510)

SYSTEM						ANALYTICAL COMPONENTS AND DAHS SOFTWARE						
Status	System ID	Para-meter	P/B	First Reporting Date	Last Reporting Date	Com-ponent ID	Status	Com-ponent Type	Sample Method (SAM)	Manufacturer	Model or Version	Serial #
A	603	GAS	P	04/01/2001	/ /	006	A	DAHS		KVB-ENERTEC	FOCUS	1953000000
						602	A	GFFM	ORF	DELTAP	ORIFICE2	20-2810
						603	A	GFFM	ORF	GULTON STATHAM	PG 3000	353A4330P006
A	604	OILV	P	04/01/2001	/ /	006	A	DAHS		KVB-ENERTEC	FOCUS	1953000000
						604	A	OFFM	O	GENERAL ELECTRIC	0424	G385256

Parameter Monitored Codes: GAS - Gas fuel flow, OILV - Volumetric oil flow
Primary/Backup Codes: P - Primary
Component Type Codes: DAHS - Data acquisition & handling system, GFFM - Gas fuel flowmeter, OFFM - Oil fuel flow meter
SAM codes: ORF - Orifice, O - Other
Status Codes: A - Add

UNIT/STACK/PIPE ID: MS2A

MONITORING SYSTEMS/ANALYTICAL COMPONENTS (RT 510)

SYSTEM						ANALYTICAL COMPONENTS AND DAHS SOFTWARE						
Status	System ID	Para-meter	P/B	First Reporting Date	Last Reporting Date	Com-ponent ID	Status	Com-ponent Type	Sample Method (SAM)	Manufacturer	Model or Version	Serial #
U	401	NOX	P	01/01/1996	/ /	006	U	DAHS		KVB-ENERTEC, INC.	FOCUS 2.1	1953000000
						401	U	NOXA	DIL	TECO	42D	42D-47918-279
						402	U	O2D	DIL	SERROMAX	ZRO	0407948

Parameter Monitored Codes: NOX - NOx emission rate
Primary/Backup Codes: P - Primary
Component Type Codes: DAHS - Data acquisition & handling system, NOXA - Dual-Range NOx analyzer, O2D - Dry O2 analyzer
SAM codes: DIL - Dilution
Status Codes: U - Unchanged

UNIT/STACK/PIPE ID: MS2B

MONITORING SYSTEMS/ANALYTICAL COMPONENTS (RT 510)

SYSTEM						ANALYTICAL COMPONENTS AND DAHS SOFTWARE						
Status	System ID	Para-meter	P/B	First Reporting Date	Last Reporting Date	Com-ponent ID	Status	Com-ponent Type	Sample Method (SAM)	Manufacturer	Model or Version	Serial #
U	301	NOX	P	01/01/1996	/ /	006	U	DAHS		KVB-ENERTEC, INC.	FOCUS 2.1	1953000000
						301	U	NOXA	DIL	TECO	42D	42D-47851-279
						302	U	O2D	DIL	SERROMAX	ZRO	2558009

Parameter Monitored Codes: NOX - NOx emission rate
Primary/Backup Codes: P - Primary
Component Type Codes: DAHS - Data acquisition & handling system, NOXA - Dual-Range NOx analyzer, O2D - Dry O2 analyzer
SAM codes: DIL - Dilution
Status Codes: U - Unchanged

UNIT/STACK/PIPE ID: MS3A

MONITORING SYSTEMS/ANALYTICAL COMPONENTS (RT 510)

SYSTEM						ANALYTICAL COMPONENTS AND DAHS SOFTWARE						
Status	System ID	Parameter	P/B	First Reporting Date	Last Reporting Date	Component ID	Status	Component Type	Sample Method (SAM)	Manufacturer	Model or Version	Serial #
A	601	NOX	P	04/01/2001	/ /	006	A	DAHS		KVB-ENERTEC	FOCUS	1953000000
						601	A	NOXA	EXT	TECO	42C	42C-67177-356
						602	A	O2D	EXT	SERVOMEX	1440	01420C11628

Parameter Monitored Codes: NOX - NOx emission rate
Primary/Backup Codes: P - Primary
Component Type Codes: DAHS - Data acquisition & handling system, NOXA - Dual-Range NOx analyzer, O2D - Dry O2 analyzer
SAM codes: EXT - Dry Extractive
Status Codes: A - Add

FACILITY NAME: CANE ISLAND ORIS CODE: 7238

UNIT/STACK/PIPE ID: MS3B

MONITORING SYSTEMS/ANALYTICAL COMPONENTS (RT 510)

SYSTEM						ANALYTICAL COMPONENTS AND DAHS SOFTWARE						
Status	System ID	Para-meter	P/B	First Reporting Date	Last Reporting Date	Com-ponent ID	Status	Com-ponent Type	Sample Method (SAM)	Manufacturer	Model or Version	Serial #
A	501	NOX	P	04/01/2001	/ /	006	A	DAHS		KVB-ENERTEC	FOCUS	1953000000
						601	A	NOXA	EXT	TECO	42C	42C-67177-356
						602	A	O2D	EXT	SERVOMEX	1440	01420C11628

Parameter Monitored Codes: NOX - NOx emission rate
Primary/Backup Codes: P - Primary
Component Type Codes: DAHS - Data acquisition & handling system, NOXA - Dual-Range NOx analyzer, O2D - Dry O2 analyzer
SAM codes: EXT - Dry Extractive
Status Codes: A - Add

Unit/Stack/Pipe ID: **1

EMISSIONS FORMULAS (RT 520)

Status	Formula ID#	Parameter	Formula Code	Formulas
U	001	SO2	D-5	F#(002) * 0.0006
U	002	HI	F-20	S#(003-103) * GCV_GAS / 10**6
U	004	CO2	G-4	(1040 * F#(002) * (1 / 385) * 44) / 2000)
U	101	SO2	D-2	2.0 * F#(105) * %S_OIL / 100
U	102	HI	F-19	F#(105) * GCV_OIL / 10**6
U	104	CO2	G-4	(1420 * F#(102) * (1 / 385) * 44) / 2000)
U	105	OILM	D-3	F#(106) * D_OIL
U	106	FOIL		S#(004-104) - S#(005-104)
U	107	NOX	F-5	(1.194 * 10**-7) * S#(001-101) * F#(109) * ((20.9) / (20.9 - S#(002-101))
U	109	FD	F-8	((X_GAS * 8710) + (X_OIL * 9190))
U	110	HI	D-15A	(F#(002) * T_GAS + F#(102) * T_OIL) / T_UNIT

Status Codes: U - Unchanged
Parameter Codes: CO2 - CO2 mass emissions, FD - Dry f-factor, FOIL - Net oil flow to unit/pipe, HI - Heat input, NOX - NOx emission rate, OILM - Mass of oil, SO2 - SO2 mass emissions

Unit/Stack/Pipe ID: 2

EMISSIONS FORMULAS (RT 520)

Status	Formula ID#	Parameter	Formula Code	Formulas
U	001	SO2	D-5	F#(002) * 0.0006
U	002	HI	F-20	S#(203-203) * GCV_GAS / 10**6
U	004	CO2	G-4	(1040 * F#(002) * (1 / 385) * 44)/ 2000
U	101	SO2	D-2	2.0 * F#(105) * %S_OIL / 100
U	102	HI	F-19	F#(105) * GCV_OIL / 10**6
U	104	CO2	G-4	(1420 * F#(102) * (1 / 385) * 44) / 2000
U	105	OILM	D-3	S#(204-204) * D_OIL
U	110	HI	D-15A	(F#(002) * T_GAS + F#(102) * T_OIL) / T_UNIT

Status Codes: U - Unchanged

Parameter Codes: CO2 - CO2 mass emissions, HI - Heat input, OILM - Mass of oil, SO2 - SO2 mass emissions

Unit/Stack/Pipe ID: 3

EMISSIONS FORMULAS (RT 520)

Status	Formula ID#	Parameter	Formula Code	Formulas
A	601	SO2	D-5	F#(602) * 0.0006
A	602	HI	F-20	S#(603-603) * GCV_GAS / 10**6
A	604	CO2	G-4	(1040 * F#(602) * (1 / 385) * 44) / 2000
A	611	SO2	D-2	2.0 * F#(615) * %S_OIL / 100
A	612	HI	F-19	F#(615) * GCV_OIL / 10**6
A	614	CO2	G-4	(1420 * F#(612) * (1 / 385) * 44) / 2000
A	615	OILM	D-3	S#(604-604) * D_OIL
A	620	HI	D-15A	(F#(602) * T_GAS + F#(612) * T_OIL) / T_UNIT
A	625	FGAS	N-GAS	S#(602-603) + S#(603-603)
A	630	CO2	G-4A	(F#(604) * T_gas + F#(614) * T_oil)/T_unit

Status Codes: A - Add

Parameter Codes: CO2 - CO2 mass emissions, FGAS - Net gas flow to unit/pipe, HI - Heat input, OILM - Mass of oil, SO2 - SO2 mass emissions

Unit/Stack/Pipe ID: MS2A

EMISSIONS FORMULAS (RT 520)

Status	Formula ID#	Parameter	Formula Code	Formulas
U	005	FD	F-8	((X_GAS * 8710) + (X_OIL * 9190))
U	107	NOX	F-5	(1.194 * 10**-7) * S#(401-401)* F#(005) * ((20.9) / (20.9 - S#(402-401))

Status Codes: U - Unchanged
Parameter Codes: FD - Dry f-factor, NOX - NOx emission rate

Unit/Stack/Pipe ID: MS2B

EMISSIONS FORMULAS (RT 520)

Status	Formula ID#	Parameter	Formula Code	Formulas
U	005	FD	F-8	((X_GAS * 8710) + (X_OIL * 9190))
U	109	NOX	F-5	(1.194 * 10**-7) * S#(301-301)* F#(005) * ((20.9) / (20.9 - S#(302-301))

Status Codes: U - Unchanged
Parameter Codes: FD - Dry f-factor, NOX - NOx emission rate

Unit/Stack/Pipe ID: MS3A

EMISSIONS FORMULAS (RT 520)

Status	Formula ID#	Parameter	Formula Code	Formulas
A	605	FD	F-8	((X_GAS * 8710) + (X_OIL * 9190))
A	607	NOX	F-5	(1.194 * 10**-7) * S#(601-601) * F#(605) * (20.9 / (20.9 - S#(602-601))

Status Codes: A - Add
Parameter Codes: FD - Dry f-factor, NOX - NOx emission rate

Unit/Stack/Pipe ID: MS3B

EMISSIONS FORMULAS (RT 520)

Status	Formula ID#	Parameter	Formula Code	Formulas
A	507	NOX	F-5	(1.194 * 10**-7) * S#(601-501) * F#(605) * (20.9 / (20.9 - S#(602-501))
A	605	FD	F-8	((X_GAS * 8710) + (X_OIL * 9190))

Status Codes: A - Add

Parameter Codes: FD - Dry f-factor, NOX - NOx emission rate

SPAN VALUES (RT 530)

Unit/ Stk ID	Para- meter	Scale	Meth- od	MPC/ MEC/ MPF	Max. NOx Rate	Span Value	Full-Scale Range	Units of Measure	Eff. Date and Hour	Inactive Date & Hour	Dual Spans Req.	Def. High Range Value
**1	NOX	H	TB	250.000	0.320	250	250	PPM	01/01/1996	/ /	D	
	NOX	L	HD	25.000	0.000	25	25	PPM	01/01/1996	/ /	D	
	O2	H				25.0	25.0	%	01/01/1996	/ /		
MS2A	NOX	H	TB	250.000	0.320	250	250	PPM	01/01/1996	/ /	D	
	NOX	L	HD	25.000	0.000	25	25	PPM	01/01/1996	/ /	D	
	O2	H				25.0	25.0	%	01/01/1996	/ /		
MS2B	NOX	H	TB	250.000	0.320	250	250	PPM	01/01/1996	/ /	D	
	NOX	L	HD	25.000	0.000	25	25	PPM	01/01/1996	/ /	D	
	O2	H				25.0	25.0	%	01/01/1996	/ /		
MS3A	NOX	H	TB	100.000	0.389	100	100	PPM	04/01/2001	/ /	D	
	NOX	L	TR	10.000	0.000	10	10	PPM	04/01/2001	/ /	D	
	O2	H				25.0	25.0	%	04/01/2001	/ /		
MS3B	NOX	H	TB	100.000	0.389	100	100	PPM	04/01/2001	/ /	D	
	NOX	L	TR	10.000	0.000	10	10	PPM	04/01/2001	/ /	D	
	O2	H				25.0	25.0	%	04/01/2001	/ /		

Parameter Codes: NOX - NOx concentration, O2 - Oxygen
Scale Codes: H - High, L - Low
Method Codes: HD - Historical data, TB - Table of Constants, TR - Test results
Units of Measure Codes: % - Percent, PPM - Parts per million
Dual Span Req. Codes: D - D Two CEMS ranges installed

UNIT AND STACK LOAD RANGE AND OPERATING LOAD (RT 535)

Unit/Stack/ Pipe ID	Units of Measure	Maximum Hourly Load	Single Load RATA Testing Only
**1	MW	50	
2	MW	90	
3	MW	252	
MS2A	MW	90	
MS2B	MW	90	
MS3A	MW	252	
MS3B	MW	252	

RANGE OF OPERATION, NORMAL LOAD AND LOAD USAGE (RT 536)

Unit/ Stack ID	Upper Bound of Range Of Operation	Lower Bound of Range Of Operation	Two Most Frequently-used Load Levels	Designated Normal Load	Second Designated Normal Load	Activation Date	Deactivation Date
**1	43	10	H,L	H	L	01/01/2000	/ /
2	90	40	H,M	H		01/01/1995	/ /
3	247	154	H,M	H		04/01/2001	/ /
MS2A	90	40	H,M	H		01/01/1995	/ /
MS2B	90	40	H,M	H		01/01/1995	/ /
MS3A	247	154	H,M	H		04/01/2001	/ /
MS3B	247	154	H,M	H		04/01/2001	/ /

FUEL FLOWMETER DATA (RT 540)

Unit/ Pipe ID	System ID	Parameter	Fuel Type	Maximum Fuel Flow Rate	Units of Measure	Source of Maximum	Initial Accuracy Test Method	Sub Status
**1	103	GAS	PNG	13423	HSCF	UMX	ILMM	U
	104	OILV	DSL	15496	GALHR	UMX	ILMM	U
2	203	GAS	PNG	37520	HSCF	UMX	ILMM	U
	204	OILV	DSL	45600	GALHR	UMX	ILMM	U
3	603	GAS	PNG	23580	HSCF	UMX	AGA3	A
	604	OILV	OIL	15000	GALHR	UMX	ILMM	A

Parameter Codes: GAS - Gas fuel flow, OILV - Volumetric oil flow
Fuel Type Codes: DSL - Diesel oil, OIL - Residual oil, PNG - Pipeline natural gas
Units of Measure Codes: GALHR - Gallons per hour, HSCF - 100 standard cubic feet per hour
Source of Maximum Codes: UMX - Unit Maximum Rate
Submission Status Codes: A - Add, U - Unchanged

MONITORING METHODOLOGIES (RT 585)

Unit ID	Parameter	Methodology	Fuel Type	Primary/ Secondary	Missing Data Approach	Begin Date	End Date
**1	CO2	GFF	PNG	P	SPTS	01/01/1998	/ /
	CO2	OFF	DSL	P	SPTS	01/01/1998	/ /
	HI	GFF	PNG	P	SPTS	01/01/1998	/ /
	HI	OFF	DSL	P	SPTS	01/01/1998	/ /
	NOXR	CEM	NFS	P	SPTS	01/01/1998	/ /
	OP	EXP	PNG	P	NA	01/01/1998	/ /
	SO2	GFF	PNG	P	SPTS	01/01/1998	/ /

MONITORING METHODOLOGIES (RT 585)

Unit ID	Parameter	Methodology	Fuel Type	Primary/ Secondary	Missing Data Approach	Begin Date	End Date
**1	SO2	OFF	DSL	P	SPTS	01/01/1998	/ /
2	CO2	GFF	PNG	P	SPTS	01/01/1995	/ /
	CO2	OFF	OIL	P	SPTS	01/01/1995	/ /
	HI	GFF	PNG	P	SPTS	01/01/1995	/ /
	HI	OFF	OIL	S	SPTS	01/01/1995	/ /
	NOXR	CEM	NFS	P	SPTS	01/01/1995	/ /
	OP	EXP	NFS	P	NA	01/01/1995	/ /
	SO2	GFF	PNG	P	SPTS	01/01/1995	/ /
	SO2	OFF	OIL	P	SPTS	01/01/1995	/ /
3	CO2	GFF	PNG	P	SPTS	04/01/2001	/ /
	CO2	OFF	OIL	P	SPTS	04/01/2001	/ /
	HI	GFF	PNG	P	SPTS	04/01/2001	/ /
	HI	OFF	OIL	S	SPTS	04/01/2001	/ /
	NOXR	CEM	NFS	P	SPTS	04/01/2001	/ /
	OP	EXP	NFS	P	NA	04/01/2001	/ /
	SO2	GFF	PNG	P	SPTS	04/01/2001	/ /
	SO2	OFF	OIL	P	SPTS	04/01/2001	/ /

Parameter Codes: CO2 - Carbon Dioxide, HI - Heat Input, NOXR - NOx Emission Rate, OP - Opacity, SO2 - Sulfur Dioxide
Fuel Type Codes: DSL - Diesel oil, NFS - Non-fuel specific, OIL - Residual oil, PNG - Pipeline natural gas
Methodology Codes: CEM - Continuous emission monitoring, EXP - Exempted, GFF - Hourly gas flow, OFF - Hourly oil flow
Missing Data Approach Codes: NA - Not applicable, SPTS - Standard Part 75

CONTROL INFORMATION (RT 586)

Unit ID	Parameter	Type of Controls	Primary/ Secondary	Original Installation?	Controls Installation Date	Controls Optim- ization Date	Controls Retirement Date	Ozone Season Only?
3	NOX	DLNB	P		04/01/2001	04/01/2001	/ /	
	NOX	H2O	P		04/01/2001	04/01/2001	/ /	
	NOX	SCR	P		04/01/2001	04/01/2001	/ /	

Parameter Codes: NOX - Nitrogen Oxides
Type of Controls Codes: DLNB - Dry Low NOx Burners (for turbine), H2O - Water injection, SCR - Selective Catalytic Reduction

FUEL TYPE INFORMATION (RT 587)

Unit ID	Fuel Classification	Primary/ Secondary Fuel	Start Date	End Date	Ozone Season Flag	Method to Qualify for Monthly GCV	Method to Qualify for Daily % Sulfur
**1	DSL	S	01/01/1995	/ /		GHS	SHS
	PNG	P	01/01/1995	/ /		GGC	SGC
2	OIL	S	01/01/1996	/ /			
	PNG	P	01/01/1996	/ /			
3	OIL	S	04/01/2001	/ /			
	PNG	P	04/01/2001	/ /			

Fuel Classification Codes: DSL - Diesel oil, OIL - Residual oil, PNG - Pipeline natural gas
GCV Method Codes: GGC - Using On-line Gas Chromatograph for 720 hours, GHS - Hourly Sampling for 720 hours
Sulfur Method Codes: SGC - Using On-line Gas Chromatograph for 720 hours, SHS - Manual Hourly Sampling for 720 hours

900CERTIFY SHARMA ABAINI K 000718DR
90101I am authorized to make this submission on behalf of the owners and
90102operators of the affected source or affected units for which the
90103submission is made. I certify under penalty of law that I have
90104personally examined, and am familiar with, the statements and
90105information submitted in this document and all its attachments.
90106Based on my inquiry of those individuals with primary
90107responsibility for obtaining the information, I certify that the
90108statements and information are to the best of my knowledge and
90109belief true, accurate, and complete. I am aware that there are
90110significant penalties for submitting false statements and
90111information or omitting required statements and information,
90112including the possibility of fine or imprisonment.

ORIS Code: 7238 State: FL
Facility Name: CANE ISLAND County: OSCEOLA

EVALUATION OF MONITORING PLAN DATA FOR STACK MS2A

Record Types	Problem Number	Description
		Based on the evaluation criteria in this version, the software has not identified any errors for this stack.

ORIS Code: 7238 State: FL
Facility Name: CANE ISLAND County: OSCEOLA

==

EVALUATION OF MONITORING PLAN DATA FOR STACK MS2B

Record Types	Problem Number	Description
		Based on the evaluation criteria in this version, the software has not identified any errors for this stack.

ORIS Code: 7238 State: FL
Facility Name: CANE ISLAND County: OSCEOLA

==

EVALUATION OF MONITORING PLAN DATA FOR STACK MS3A

Record Types	Problem Number	Description
		Based on the evaluation criteria in this version, the software has not identified any errors for this stack.

ORIS Code: 7238 State: FL
Facility Name: CANE ISLAND County: OSCEOLA

EVALUATION OF MONITORING PLAN DATA FOR STACK MS3B

Record Types	Problem Number	Description
		Based on the evaluation criteria in this version, the software has not identified any errors for this stack.

ORIS Code: 7238 State: FL
Facility Name: CANE ISLAND County: OSCEOLA

==

EVALUATION OF MONITORING PLAN DATA FOR UNIT **1

Record Types	Problem Number	Description
		Based on the evaluation criteria in this version, the software has not identified any errors for this unit.

ORIS Code: 7238 State: FL
Facility Name: CANE ISLAND County: OSCEOLA

EVALUATION OF MONITORING PLAN DATA FOR UNIT 2

Record Types	Problem Number	Description
		Based on the evaluation criteria in this version, the software has not identified any errors for this unit.

ORIS Code: 7238 State: FL
Facility Name: CANE ISLAND County: OSCEOLA

EVALUATION OF MONITORING PLAN DATA FOR UNIT 3

Record Types	Problem Number	Description
		Based on the evaluation criteria in this version, the software has not identified any errors for this unit.

Attachment D
Compliance Certification

"I, the undersigned, am the responsible official as defined in Chapter 62-210.200, F.A.C., of the Title V source 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."

Arl Sharma ______________________ 10/12/2001 __________

Signature Date

Attachment E
Fuel Analysis

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.

ANALYTICAL CHEMISTS SINCE 1900

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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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						
	R HEATING VALUE (GAS)	ASTM 1945-80/GPA 2261-90			4/25/95	15:00	EVM
	EN		0.32	%	4/25/95	15:00	EVM
	ME...ANE		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
	ANE		95.24	%	4/25/95	15:00	EVM
			2.54	%	4/25/95	15:00	EVM

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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
2	GAS 01, #2						
	PROP[illegible]E		0.65	%	4/25/95	15:00	EVM
	[illegible]TANE		0.19	%	4/25/95	15:00	EVM
	[illegible]ANE		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		20,857.03	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
	[illegible]PENTANE		0.06	%	4/25/95	15:00	EVM

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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
3	GAS 01-02, #3						
	[illegible]ENTANE		0.03	%	4/25/95	15:00	EVM
	[illegible] ES		<0.02	%	4/25/95	15:00	EVM
	CARBON 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
	[illegible]BON DIOXIDE		0.67	%	4/25/95	15:00	EVM
	[illegible]RY (HIGH HEAT VAL)		1040.72	BTU/CU.FT.	4/25/95	15:00	EVM

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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
4	GAS 02, #4						
	BTU, SAT. (HIGH HEAT VAL)		1022.61	BTU/CU.FT.	4/25/95	15:00	EVM
	NET BTU, DRY (LOW HEAT VAL)		930.35	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		930.35	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
	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
	REAL SPECIFIC GRAVITY		0.5875		4/25/95	15:00	EVM

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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
5	GAS 02, #5						
	ACTUAL NET BTU		936.71	BTU/CU.FT.	4/25/95	15:00	EVM
	[illegible] NET BTU		20,844.55	BTU/LB.	4/25/95	15:00	EVM
	DEN[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
	[illegible]THANE		95.35	%	4/25/95	15:00	EVM
	[illegible]HANE		2.49	%	4/25/95	15:00	EVM
	ROPANE		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
	[illegible]		0.044875676	LBS/CU.FT.	4/25/95	15:00	EVM

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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.

SP	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
	[illegible]		2.16	%	5/12/95	10:00	EVM
	[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)		920.25	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		920.25	BTU/CU.FT.	5/12/95	10:00	EVM
	ACTUAL NET BTU		20,785.88	BTU/LB.	5/12/95	10:00	EVM
	DENSITY		0.000706968	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%

Attachment F
Control Equipment Description

APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Cane Island Power Park Unit 3
Kissimmee Utility Authority
PSD-FL-254 and PA98-38
Intercession City, Osceola County, Florida

BACKGROUND

The applicant, Kissimmee Utility Authority (KUA), proposes to install a nominal 250 megawatt (MW) (net) combined cycle combustion turbine at the existing Cane Island Power Park, located at 6075 Old Tampa Highway, near Intercession City, Osceola County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM and PM_{10}), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_X). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rules 62-212.400, F.A.C.

The primary unit to be installed is a nominal 167 MW, General Electric PG7241FA (7FA) combustion turbine-electrical generator, fired primarily with pipeline natural gas. The project includes an 80-90 MW heat recovery steam generator (HRSG) with a steam turbine-electrical generator. Duct burners will be installed in the HRSG for supplemental firing to compensate for reduced combustion turbine capacity at high ambient temperature. The project also includes a new 1 million gallon storage tank for backup No. 2 fuel oil, cooling tower, 130 foot stack for combined cycle operation, and a 100 foot bypass stack for simple cycle operation. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated January 8, 1999, accompanying the Department's Intent to Issue.

BACT APPLICATION:

The application was received on August 5, 1998 and included a proposed BACT proposal prepared by the applicant's consultant, Black & Veatch. A revision which reduced the proposed emission limits was received on November 6 through a Response to Statement of Sufficiency. A draft BACT was issued by the Department on January 7, 1999. It was revised on March 25 as a result of comments received by the Department. The revised version was introduced by KUA into the record of the Administrative Hearing held on June 1 pursuant to the Site Certification requirements of the Florida Power Plant Siting Acton. The draft BACT included therein constitutes KUA's most recent BACT proposal. The proposal is summarized in the table below.

POLLUTANT	CONTROL TECHNOLOGY	BACT PROPOSAL
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity 5 ppmvd Ammonia Slip if SCR is used
VOC	As Above	1.4 ppm (Gas, CT on, DB off) 4 ppm (Gas, CT and DB on)) 10 ppm for F.O.
CO	As Above	12 ppmvd (Gas, CT on, DB off) 20 ppmvd (Gas, CT and DB on) 30 ppmvd for F.O.
NO_X (CT on, DB off)	DLN, or DLN & SCR for gas WI or SCR for fuel oil 720 Hours on fuel oil with DB On or Off	9 ppmvd (DLN) or 4.5 ppmvd (SCR) for gas 42 ppmvd (WI) or 15 ppmvd (SCR) for fuel oil 12/42 ppmvd (gas/oil) Intermittent Simple Cycle
NO_X (CT and DB on)	DLN & Low NO_X, or DLN & SCR for gas WI & Low NO_X, or SCR for fuel oil Duct burner only fires natural gas	9.4 ppmvd (DLN) or 4.5 ppmvd (SCR) for gas 42 ppmvd (WI) or 15 ppmvd (SCR) for fuel oil DB limited to 0.4 lb/MW-hr

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (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:

- Any Environmental Protection Agency determination of BACT 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.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- 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 unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then 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.

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2. (assuming 25 percent efficiency) and 150 ppmvd SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). The BACT proposed by the KUA is consistent with the NSPS which allows NO_X emissions in the range of 110 ppmvd for the high efficiency unit to be purchased by the Kissimmee Utility Authority. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

The duct burner required for supplementary gas-firing of the HRSG at high ambient temperatures is subject to 40 CFR 60, Subpart Dc, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978. There are no NSPS-based emission limits for these small units when firing natural gas.

DETERMINATIONS BY EPA AND STATES:

The following table is a sample of information on some recent BACT determinations by States in the South for combined cycle stationary gas turbine projects. These are projects incorporating large prime movers capable of producing more than 150 MW excluding the steam cycle. Such units are typically categorized as F or G Class Frame units. The greatest activity in combined cycle installations appears to be in Texas, Florida, and Alabama. The KUA draft BACT is included for reference.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

TABLE 1

RECENT BACT LIMITS FOR NITROGEN OXIDES FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	Power Output Megawatts	NO_X Limit ppmvd @ 15% O_2 and Fuel	Technology	Comments
Mobile Energy, AL	~250	~3.5 - NG (CT&DB) ~11 – FO (CT&DB)	DLN & SCR	178 MW GE 7FA CT 1/99 585 mmBtu Duct Burner
Alabama Power Barry	800	4.8* - NG Permit Limit is 0.018 lb/mmBtu	DLN & SCR	3x170 MW GE 7FA CTs 11/98 Cannot meet 9 ppmvd w/o SCR Large DB and Pwr Augmentation
Alabama Power Theo	210	4.8* – NG Proposed Limit is 0.018 lb/mmBtu	DLN & SCR	4x170 MW GE 7FA CTs 11/98 Cannot meet 9 ppmvd w/o SCR Large DB and Pwr Augmentation
KUA Cane Island 3	250	9/4.5 - NG (CT) 9.4/4.5 - (CT&DB) 42/15 - FO	DLN/SCR DLN/SCR WI/SCR	170 MW GE 7FA. 11/99 Increase allowed for DB. If SCR, **ammonia** slip = 5 ppmvd
Lake Worth LLC, FL	250	9/3.5 - NG (CT) 9.4/3.5 - (CT&DB) 42 - FO	DLN/SCR DLN/SCR WI	170 MW GE 7FA. 11/99 Increase allowed for DB. Project repowers one+ units
Lakeland, FL	350	9/7.5 – NG 42/15 – FO	DLN/SCR WI/SCR	250 MW WH 501G 7/98 Initially 250 MW simple cycle and 25 ppmvd NO_X limit on gas
Santa Rosa, FL	241	9 - NG (CT) 9.8/6 (CT&DB)	DLN DLN/SCR	170 MW GE 7FA CT. 12/98 6 ppmvd if SCR or SNCR
Tallahassee, FL	260	12 - NG 42 - No. 2 FO	DLN	160 MW GE 7FA CT. 7/98 DLN guarantee is 9 ppmvd
LSP Batesville, MI	~800	9 - NG 42 - No. 2 FO	DLN & SCR WI	3x185 MW WH 501F CTs. 11/97 Revised 7/98. Large DB Cannot meet 9 ppmvd w/o SCR
Miss Power Daniel	1000	4.8* – NG Permit Limit is 0.018 lb/mmBtu	DLN & SCR	4x170 MW GE 7FA CTs 11/98 Cannot meet 9 ppmvd w/o SCR Large DB and Pwr Augmentation
Panda Guadalupe TX	1000	9 - NG	DLN	4x170 MW GE 7FA CTs 2/99
Hays San Marco, TX	1080	5 - NG	SCR	4x175 ABB GT24 CTs. 6/99 Cannot meet 9 ppmvd w/o SCR
Duke Hidalgo, TX	520	12 - NG	DLN	2x170 MW GE 7FA CTs 12/98
Tenaska Rusk, TX	888	9 - NG	DLN	3x164 MW GE 7FA CT. 5/99
Sabine River, TX	440	6 - NG	DLN & SCR	2 x170 MW GE 7FA CTs 6/99
GTP/Calpine, TX	500	5 – NG	SCR	2x183 MW WH501F CTs 9/99 Cannot meet 9 ppmvd w/o SCR

DB = Duct Burner — DLN = Dry Low NO_X Combustion — GE = General Electric
NG = Natural Gas — SCR = Selective Catalytic Reduction — WH = Westinghouse
FO = Fuel Oil — WI = Water or Steam Injection — ABB = Asea Brown Bovari

- Reportedly revised in mid-1999 to 0.013 lb/mmBtu which equals 3.5 ppmvd

There are more than 20 applications pending for similar projects in Texas with similar BACT proposals as indicated above. There are numerous applications for similar projects throughout the Southeast including Florida, all of which include BACT proposals within the range of the determinations given above.

TABLE 2

RECENT BACT LIMITS FOR CARBON MONOXIDE, VOLATILE ORGANIC COMPOUNDS, PARTICULATE MATTER, AND VISIBILITY FOR LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS

Project Location	**CO - ppmvd (or lb/mmBtu)**	**VOC - ppm (or lb/mmBtu)**	**PM - lb/mmBtu (or gr/dscf or lb/hr)**	**Technology and Comments**
Mobile Energy, AL	~18 – NG (CT&DB) ~26 – FO (CT&DB)	~5 – NG ~6 - FO	10% Opacity	Clean Fuels Good Combustion
Alabama Power Barry	~15 – NG(CT) ~25 – NG(DB & CT)	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/mmBtu – (CT) 0.011 lb/mmBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion
Alabama Power Theo	~36 – CT & DB	~12.5 CT & DB		Clean Fuels Good Combustion
KUA Cane Island	10 - NG (CT) 20 - NG (CT&DB) 30 - FO	1.4 - NG (CT) 4 - NG (CT&DB) 10 - FO	10% Opacity	Clean Fuels Good Combustion
Lake Worth LLC, FL	9 - NG (CT) 15 – NG (CT & DB) 20 - F.O. (3-hr)	1.4 - NG (CT) 1.8 - NG (CT & DB) 3.5 – F.O.	10% Opacity	Clean Fuels Good Combustion
Lakeland	25 – NG or 10 by Ox Cat 75 – FO	4 – NG 10 – FO	10%	Clean Fuels Good Combustion
Santa Rosa, FL	9 - NG (CT) 24 - NG (CT&DB)	1.4 - NG (CT) 8 - NG (CT&DB)	10% Opacity	Clean Fuels Good Combustion
Tallahassee, FL	25 – NG 90 – FO			Clean Fuels Good Combustion
LSP Batesville, MI	30 at > 75% load - NG 36 at > 75% load - FO	9 at > 75% load – NG 15 at > 75% load - FO	40% Opacity	Clean Fuels Good Combustion
Miss Power Daniel	~15 - NG(CT) ~25 – NG(DB & CT	~8 - NG(CT) ~12 – NG(CT & DB)	0.010 lb/mmBtu – (CT) 0.011 lb/mmBtu -(CT/DB) 10% Opacity	Clean Fuels Good Combustion
Panda Guadalupe TX	15 - NG			Clean Fuels Good Combustion
Hays San Marco, TX	9 - NG			Clean Fuels Good Combustion
Duke Hidalgo, TX	20 - NG			Clean Fuels Good Combustion
Tenaska Rusk, TX	25 - NG			Clean Fuels Good Combustion
Sabine River, TX	15 - NG			Clean Fuels Good Combustion
GTP/Calpine, TX	10 or 25			Clean Fuels Good Combustion

The following table is derived from the information given above for projects incorporating duct burners within supplementally-fired heat recovery steam generators. There are a number of projects from the lists above for which the Department did not obtain the details regarding the duct burners. The main focus was on NO_X emissions.

TABLE 3

RECENT BACT LIMITS FOR NITROGEN OXIDES FROM LARGE STATIONARY GAS TURBINE COMBINED CYCLE PROJECTS WITH DUCT BURNERS

Project Location	Duct Burner Rated Heat Input (mmBtu/hr)	NO_X Limit (lb/mmBtu or ppmvd)	Technology	Comments
Mobile Power, FL	585	3.5	SCR	Combined CT & DB
Alabama Power Barry	159	4.8	SCR	Combined CT & DB Possibly revised to 3.5
Alabama Power Theo		4.8	SCR	Combined CT & DB Possibly revised to 3.5
KUA Cane Is, FL	44	9.4/4.5 - (CT&DB) 42/15 - FO	DLN or DLN & SCR DLN or DLN & SCR WI or WI & SCR	Gas-fired Duct Burner Low NO_X Burners on DB Max 0.4 lb/MW-hr on DB
Santa Rosa, FL	585	9.8/6 (CT&DB)	DLN or DLN & SCR	Gas-fired Duct Burner Low NO_X Burners on DB Max 0.4 lb/MW-hr on DB
Miss Power Daniel	159	4.8	SCR	Combined CT & DB Possibly revised to 3.5
Saranac Energy, NY	553	0.08 lb/mmBtu	SCR	2 GE 7EA CTs with DBs Permit issued 1992
Bermuda HEL, VA	197	9	Steam Injection, SCR	1175 mmBtu/hr CT (1992)
Bear Island Paper, VA	129	9	SCR	474 mmBtu/hr CT (1992)
Pilgrim Energy, NY	214	4.5 (CT) 0.012 lb/mmBtu (DB)	Steam Injection, SCR Low NO_X Burner, SCR	2 WH 501D5 CTs 2 Duct Burners
Selkirk Cogen, NY	206	9 (CT) 0.018 lb/mmBtu (DB)	Low NO_X Burner, SCR	1173 mmBtu/hr CT
Grays Ferry, PA	366	9 (CT) 0.09 lb/mmBtu (DB)	DLN Low NO_X Burner	WH 501D5A CT with DB DLN Failed, SCR Required

OTHER INFORMATION AVAILABLE TO THE DEPARTMENT:

Besides the initial information submitted by the applicant, the summary above, and the references at the end of this document, key information reviewed by the Department includes:

- Comments from the National Park Service dated, September 11 1998
- Master Overview for Alabama Power Plant Barry Project received in 1998
- Master Overview for Mississippi Power Plant Daniel Project received in 1998
- Letters from EPA Region IV dated February 2, and November 8, 1999 regarding KUA Cane Island Unit 3
- Presentations by Black & Veatch and General Electric at EPA Region IV on March 4, 1999
- Letter from Black & Veatch to EPA Region IV dated March 10, 1999
- Letter from Black & Veatch to the Department and EPA Region IV dated March 24, 1999
- Texas Natural Resource Conservation Commission Draft Tier I BACT for August, 1999

- Texas Natural Resource Conservation Commission Website – www.tnrcc.state.tx.us
- DOE website information on Advanced Turbine Systems Project
- Alternative Control Techniques Document - NO_X Emissions from Stationary Gas Turbines
- General Electric 39th Turbine State-of-the-Art Technology Seminar Proceedings
- GE Guarantee for Jacksonville Electric Authority Kennedy Plant Project
- GE Power Generation - Speedtronic™ Mark V Gas Turbine Control System
- GE Combined Cycle Startup Curves
- Coen website information and brochure on Duct Burners

REVIEW OF NITROGEN OXIDES CONTROL TECHNOLOGIES:

Some of the discussion in this section is based on a 1993 EPA document on Alternative Control Techniques for NO_X Emissions from Stationary Gas Turbines. Project-specific information is included where applicable.

Nitrogen Oxides Formation

Nitrogen oxides form in the gas turbine combustion process as a result of the dissociation of molecular nitrogen and oxygen to their atomic forms and subsequent recombination into seven different oxides of nitrogen. Thermal NO_X forms in the high temperature area of the gas turbine combustor. Thermal NO_X increases exponentially with increases in flame temperature and linearly with increases in residence time. Flame temperature is dependent upon the ratio of fuel burned in a flame to the amount of fuel that consumes all of the available oxygen.

By maintaining a low fuel ratio (lean combustion), the flame temperature will be lower, thus reducing the potential for NO_X formation. Prompt NO_X is formed in the proximity of the flame front as intermediate combustion products. The contribution of Prompt to overall NO_X is relatively small in near-stoichiometric combustors and increases for leaner fuel mixtures. This provides a practical limit for NO_X control by lean combustion.

Fuel NO_X is formed when fuels containing bound nitrogen are burned. This phenomenon is not important when combusting natural gas. Although low sulfur fuel oil has more fuel-bound nitrogen than natural gas its use is limited to 720 hours per year.

Uncontrolled emissions range from about 100 to over 600 parts per million by volume, dry, corrected to 15 percent oxygen (ppmvd @15% O_2). The Department estimates uncontrolled emissions at approximately 200 ppmvd @15% O_2 for the proposed KUA turbine. The proposed NO_X controls will reduce these emissions significantly.

NO_X Control Techniques

Wet Injection

Injection of either water or steam directly into the combustor lowers the flame temperature and thereby reduces thermal NO_X formation. Typical emissions achieved by wet injection are in the range of 15–25 ppmvd when firing gas and 42 ppmvd when firing fuel oil in large combustion turbines. These values often form the basis, particularly in combined cycle turbines, for further reduction to BACT limits by other techniques. Carbon monoxide (CO) and hydrocarbon (HC) emissions are relatively low for most gas turbines. However steam and (more so) water injection may increase emissions of both of these pollutants.

Combustion Controls

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

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

To further reduce NO_X emissions, GE developed the DLN-2.0 (cross section shown in Figure 1) wherein air usage (other than for premixing) was minimized. The venturi and the centerbody assembly were eliminated and each combustor has a single burning zone. So-called "quaternary fuel" is introduced through pegs located on the circumference of the outward combustion casing.

GE has made further improvements in the DLN design. The most recent version is the DLN-2.6 (proposed for the KUA project). The combustor is similar to the DLN-2 with the addition of a sixth (center) fuel nozzle. The emission characteristics of the DLN-2.6 combustor while firing natural gas are given in Figure 2 for a unit tuned to meet a 15 ppmvd NO_X limit (by volume, dry corrected to at 15 percent oxygen) at JEA's Kennedy Station.

NO_X concentrations are higher in the exhaust at lower loads because the combustor does not operate in the lean pre-mix mode. Therefore such a combustor emits NO_X at concentrations of 15 ppmvd at loads between 50 and 100 percent of capacity, but concentrations as high as 100 ppmvd at less than 50 percent of capacity. Note that VOC comprises a very small amount of the "unburned hydrocarbons" which in turn is mostly non-VOC methane.

The combustor can be tuned differently to achieve emissions as low as 9 ppmvd of NO_X and 9 ppmvd of CO. Emissions characteristics by wet injection NO_X control while firing oil are expected to be similar for the DLN-2.6 as they are for those of the DLN-2.0 shown in Figure 3. Simplified cross sectional views of the totally premixed (while firing natural gas) DLN-2.6 combustor to be installed at the KUA project are shown in Figure 4.

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

Larger units, such as the Westinghouse 501 G or the planned General Electric 7H, use steam in a closed loop system to provide much of the cooling. The fluid is circulated through the internal portion of the nozzle component or around the transition piece between the combustor and the nozzle and does not enter the exhaust stream. Instead it is normally sent back to a steam generator. The difference between flame temperature and firing temperature into the first stage is minimized and higher efficiency is attained.

Another important result of steam cooling is that a higher firing temperature can be attained with no increase in flame temperature. Flame temperatures and NO_X emissions can therefore be maintained at comparatively low levels even at high firing temperatures. At the same time, thermal efficiency should be greater when employing steam cooling. A similar analysis applies to steam cooling around the transition piece between the combustor and first stage nozzle.

The relationship between flame temperature, firing temperature, unit efficiency, and NO_X formation can be appreciated from Figure 5 which is from a General Electric discussion on these principles. In addition to employing pre-mixing and steam cooling, further reductions are accomplished through design optimization of the burners, testing, further evaluation, etc.

At the present time, emissions achieved by combustion controls are as low as 9 ppmvd from large gas turbines, such as the GE 7FA line. Specialized dual fuel DLN burners were installed in a project in Israel[1], but their performance on fuel oil is not known to the Department.

Figure 6 is an example of an in-line duct burner arrangement and an individual burner. Since duct burners operate at lower temperature and pressure than the combustion turbine, the potential for emissions is generally lower. Furthermore the duct burner size is only 44 mmBtu/hr compared with the turbine that can accommodate a heat input greater than 1600 mmBtu/hr (LHV). The duct burner will be of a Low NO_X design and will be used to compensate for loss of capacity at high ambient temperatures.

Selective Catalytic Combustion

Selective catalytic reduction (SCR) is an add-on NO_X control technology that is employed in the exhaust stream following the gas turbine. SCR reduces NO_X emissions by injecting ammonia into the flue gas in the presence of a catalyst. Ammonia reacts with NO_X in the presence of a catalyst and excess oxygen yielding molecular nitrogen and water. The catalysts used in combined cycle, low temperature applications (conventional SCR), are usually vanadium or titanium oxide and account for almost all installations. For high temperature applications (Hot SCR up to 1100 °F), such as simple cycle turbines, zeolite catalysts are available but used in few applications to-date. SCR units are typically used in combination with wet injection or DLN combustion controls.

In the past, sulfur was found to poison the catalyst material. Sulfur-resistant catalyst materials are now becoming more available. Catalyst formulation improvements have proven effective in resisting sulfur-induced performance degradation with fuel oil in Europe and Japan, where conventional SCR catalyst life in excess of 4 to 6 years has been achieved, while 8 to 10 years catalyst life has been reported with natural gas.

As of early 1992, over 100 gas turbine installations already used SCR in the United States. Only one combustion turbine project in Florida (FPC Hines Power Block 1) employs SCR. The equipment was installed on a temporary basis because Westinghouse had not yet demonstrated emissions as low as 12 ppmvd by DLN technology at the time the units were to start up in 1998. Seminole Electric will install SCR on a previously permitted 501F unit at the Hardee Unit 3 project. The reasons are similar to those for the FPC Hines Power Block I.

Figure 7 below is a diagram of a HRSG including an SCR reactor with honeycomb catalyst and the ammonia injection grid. The SCR system lies between low and high pressure steam systems where the temperature requirements for conventional SCR can be met. Figure 8 is a photograph of FPC Hines Energy Complex.

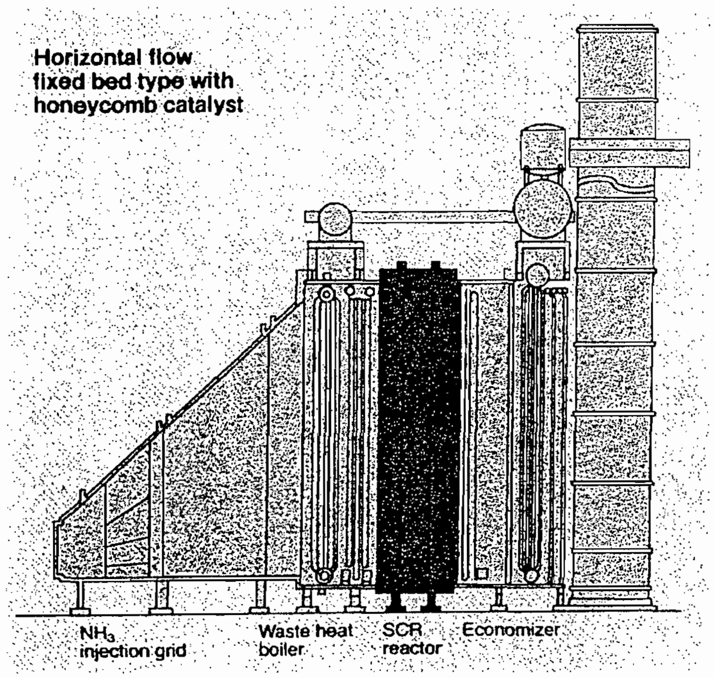

Figure 7 – SCR System within HRSG

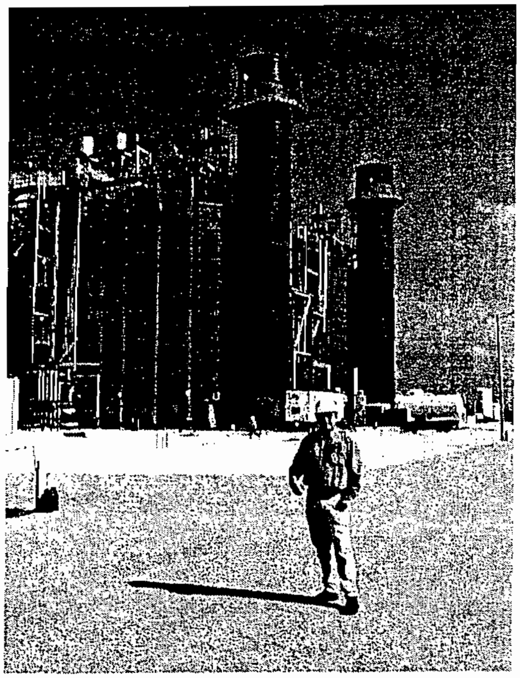

Figure 8 – FPC Hines Power Block I

The external lines to the ammonia injection grid are easily visible in Figure 8. The magnitude of the installation can be appreciated from the relative size compared with nearby individuals and vehicles.

Excessive ammonia use tends to increase emissions of CO, ammonia (slip), and particulate matter (when sulfur bearing fuels are used). Permit limits as low as 2 to 3.5 ppmvd NO_X have been specified using SCR on combined cycle F Class projects throughout the country. Permit BACT limits as low as 3.5 ppmvd NO_X have been specified using SCR for at least one F Class project (with large in-line duct burners) in the Southeast.

In a project such as KUA Cane Island, the DLN system will reduce potential emissions from about 200 ppmvd to 9 ppmvd while firing gas. Such a DLN system is a sophisticated combustion system that optimizes efficiency and emissions. An SCR system at KUA would further reduce emissions to about 4.5 ppmvd at a substantial cost and obviously with add-on control equipment that does nothing to enhance efficiency. It increases PM formation and substitutes another pollutant (ammonia) while bringing NO_X emissions to levels equal to the uncertainty in the measurement method.

Selective Non-Catalytic Combustion

Selective non-catalytic reduction (SNCR) reduction works on the same principle as SCR. The differences are that it is applicable to hotter streams than conventional or hot SCR, no catalyst is required, and urea can be used as a source of ammonia. No applications have been identified wherein SNCR was applied to a gas turbine because the exhaust temperature of 1100 °F is too low to support the NO_X removal mechanism.

The acceptable temperature for the removal reactions is between 1400 and 2000 °F. A supplementally-fired HRSG is defined as a HRSG fired to an average temperature not exceeding about 1800 °F. The 44 mmBtu/hr duct burner described by KUA will not achieve these temperatures close to this value. Although it is one of the approved options for the Santa Rosa Energy Center, which incorporates a 585 mmBtu/hr duct burner, SNCR does not appear to be feasible for KUA's project.

Emerging Technologies: SCONOX™ and XONON™

SCONO$_X$™ is a catalytic technology that achieves NO_X control by oxidizing and then absorbing the pollutant onto a honeycomb structure coated with potassium carbonate. The pollutant is then released as harmless molecular nitrogen during a regeneration cycle that requires dilute hydrogen gas. The technology has been demonstrated on small units in California and has been purchased for a small source in Massachusetts.[2] California regulators and industry sources have stated that the first 250 MW block to install SCONOx ™ will be at PG&E's La Paloma Plant near Bakersfield.[3] The overall project includes several more 250 MW blocks with SCR for control.[4] USEPA has identified an "achieved in practice" BACT value of 2.0 ppmvd over a three-hour rolling average based upon the recent performance of a Vernon, California natural gas-fired 32 MW combined cycle turbine (without duct burners) equipped with the patented SCONOx™ system

SCONOx™ technology (at 2.0 ppmvd) is considered to represent LAER in non-attainment areas where cost is not a factor in setting an emission limit. It competes with less-expensive SCR in those areas, but has the advantages that it does not cause ammonia emissions in exchange for NO_X reduction. Advantages of the SCONOx ™ process include in addition to the reduction of NO_X, the elimination of ammonia and the control of VOC and CO emissions. SCONO$_X$™ has not been applied on any major sources in ozone attainment areas.

In a letter dated March 23, 1998 to Goal Line Environmental Technologies, the SCONOx™ process was deemed as technically feasible for maintaining NO_X emissions at 2 ppmvd on a combined cycle unit. <u>ABB Environmental</u> was announced on September 10, 1998 as the exclusive licensee for SCONOx™ for United States turbine applications larger than 100 MW. <u>ABB Power Generation</u> has stated that scale up and engineering work will be required before SCONOx™ can be offered with commercial guarantees for large turbines (based upon letter from Kreminski/Broemmelsiek of ABB Power Generation to the Massachusetts Department of Environmental Protection dated November 4, 1998).

XONON™, which works by partially burning fuel in a low temperature pre-combustor and completing the combustion in a catalytic combustor. The overall result is low temperature partial combustion (and thus lower NO_X combustion) followed by flameless catalytic combustion to further attenuate NO_X formation. The technology has been demonstrated on combustors on the same order of size as SCONO$_X$™ has. XONON™ avoids the emissions of ammonia and the need to generate hydrogen. It is also extremely attractive from a mechanical point of view.

Catalytica Combustion Systems, Inc. develops, manufactures and markets the XONON™ Combustion System. In a press release on October 8, 1998 Catalytica announced the first installation of a gas turbine equipped with the XONON™ Combustion System in a municipally owned utility for the production of electricity. The turbine was started up on that day at the Gianera Generating Station of Silicon Valley Power, a municipally owned utility serving the City of Santa Clara, Calif. The XONON™ Combustion System, deployed for the first time in a commercial setting, is designed to enable turbines to produce environmentally sound power without the need for expensive cleanup solutions. Previously, this XONON™ system had successfully completed over 1,200 hours of extensive full-scale tests which documented its ability to limit emissions of nitrogen oxides, a primary air pollutant, to less than 3 parts per million.

In a definitive agreement signed on November 19, 1998, GE Power Systems and Catalytica agreed to cooperate in the design, application, and commercialization of XONON™ systems for both new and installed GE E and F-class turbines used in power generation and mechanical drive applications. This appears to be an up-and-coming technology, the development of which will be watched closely by the Department for future applications. It is not yet available for fuel oil and cycling operation.

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

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

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and will be used for approximately 720 hours per year making any conceivable add-on control technique for PM/PM_{10} either unnecessary or impractical.

A technology review indicated that the top control option for PM/PM_{10} is a combination of good combustion practices, fuel quality, and filtration of inlet air.

REVIEW OF CARBON MONOXIDE(CO) CONTROL TECHNOLOGIES

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

Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millenium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppmvd. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric will install oxidation catalyst to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[5]

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations typically achieve emissions between 10 and 30 ppmvd at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. KUA proposes to meet a limit of 10 ppmvd while firing natural gas with the small duct burner off. The higher values of 20 and 30 while firing gas or fuel oil with the duct burner operating are still within the range. The present proposal is a big improvement compared to the original proposal of 25 ppmvd when firing gas and 90 ppmvd when firing oil.

According to recent test data reviewed by the Department, actual CO emissions from large F Class frame units are less than 5 ppmvd, even when firing fuel oil. The Department has not reviewed an extensive body of actual data, but has reasonable assurance that the GE PG7241FA unit selected by KUA will achieve values well below those proposed without requiring installation of an oxidation catalyst.

REVIEW OF VOLATILE ORGANIC COMPOUND (VOC) CONTROL TECHNOLOGIES

Volatile organic compound (VOC) emissions, like CO emissions, are formed due to incomplete combustion of fuel. The high flame temperature is very efficient at destroying VOC. The applicant has proposed good combustion practices to control VOC. The limits proposed by KUA for this project are 1.4 ppm for gas with the duct burner off or 4 ppm with the duct burner on. The limit proposed by KUA is 10 ppm for oil firing whether the duct burner is on or off. According to GE, VOC emissions less than 1.4 ppm were achieved during recent tests of the DLN-2.6 technology when firing natural gas.[6]

Based on the chosen equipment, the Department believes VOC emissions will actually be well within the values proposed by KUA.

BACKGROUND ON SELECTED GAS TURBINE

KUA plans to the purchase a 167 MW (nominal) General Electric 7FA combined cycle gas turbine with a supplementary-fired heat recovery steam generator (HRSG) equipped with a small duct burner and a steam turbine-electrical generator to produce an additional 80-90 of electrical power. The 44 mmBtu/hr duct burner will incorporate a low NO_X design.

The first commercial GE 7F (or 7FA) unit was installed in a combined cycle project at the Virginia Power Chesterfield Station in 1990.[7] The initial units had a firing temperature of 2300 °F and a combined cycle efficiency exceeding 50 percent. By the mid-90s, the line was improved by higher combustor pressure, a firing temperature of 2400 °F, and a combined cycle efficiency of approximately 56 percent based on a 167 MW combustion turbine.

The first GE 7F/FA project in Florida was at the FPL Martin Plant in 1993 and entered commercial service in 1994.[8] The units were equipped with DLN-2 combustors with a permitted NO_X limit of 25 ppmvd. These actually achieved emissions of 13-25 ppmvd of NO_X, 0-3 ppmvd of CO, and 0-0.17 ppmvd of VOC.[9] The City of Tallahassee received a permit in 1998 to install a GE PG7231FA combustion turbine at its Purdom Plant.[10] Although permitted emissions are 12 ppmvd of NO_X, the City obtained a performance guarantee from GE of 9 ppmvd.[11]

FPL also obtained a guarantee and permit limit of 9 ppmvd NO_X for fourteen GE 7241FA turbines to be installed at the Fort Myers and Sanford Repowering Projects.[12, 13] The Santa Rosa Energy Center and the Lake Worth LLC Project in Florida received permits with a 9 ppmvd NO_X BACT limit for GE 7241FA turbines with DLN-2.6 burners.[14] Further examples are given in Table 1 above.

General Electric has primarily relied on further advancement and refinement of DLN technology to provide sufficient NO_X control for their combustion turbines in Florida. When required by BACT determinations of most states, General Electric incorporates SCR in combined cycle projects.[15] In its recent permits, Florida has included separate and lower limits in the event that GE's DLN technology does not achieve 9 ppmvd or the applicant selects a manufacturer that does not provide combustors capable of meeting 9 ppmvd.

GE's approach of progressively refining such technology is a proven one, even on some relatively large units. Recently GE Frame 7FA units met performance guarantees of 9 ppmvd with "DLN-2.6" burners at Fort St. Vrain, Colorado and Clark County, Washington.[16] Although the permitted limit is 15 ppmvd, GE has already achieved emission levels of approximately 6-7 ppmvd on gas at a dual-fuel 7EA (120 MW combined cycle) KUA Cane Island Unit 2.[17] Unit 2 is equipped with DLN-1 combustors. According to GE, similar performance is expected soon on the 7FA line such as the one that will be installed for the KUA Project. Performance guarantees less than 9 ppmvd can be expected for DLN-2.6 combustors on units delivered in a couple of years.[18]

The 9 ppmvd NO_X limit on natural gas during baseload requested by KUA is typical compared with recent BACT determinations for F Class units, such as those previously listed. The 4.5 ppmvd value for the SCR option is in-line with the recent projects listed in Table 1 that incorporate the SCR option. Although at least one of those projects has a limit of 3.5 ppmvd, it is noted that none of the projects on the list has an ammonia slip limit. The KUA ammonia limit of 5 ppmvd is lower than the typical slip guarantee value.

The GE Speedtronic™ Mark V Gas Control System will be used. This control system is designed to fulfill all gas turbine control requirements. These include control of liquid, gas, or both fuels in accordance with the requirements of the speed, load control under part-load conditions, temperature control under maximum capability conditions, or during start-up conditions. The Mark V also monitors the DLN process and controls fuel staging and combustion modes to maintain the programmed NO_X values.[19]

DEPARTMENT BACT DETERMINATION

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

Following are the BACT limits determined for the KUA project assuming full load. Values for NO_X are corrected to 15% O_2. The emission limits or their equivalents in terms of pounds per hour and NSPS units, as well as the applicable averaging times, are given in the permit Specific Conditions No. 24 through 29.

POLLUTANT	CONTROL TECHNOLOGY	BACT DETERMINATION
PM/PM_{10}, VE	Pipeline Natural Gas Good Combustion	10 Percent Opacity 5 ppmvd Ammonia Slip if SCR is used
VOC	As Above	1.4 ppm (Gas, CT on, DB off) 4 ppm (Gas, CT and DB on)) 10 ppm for F.O.
CO	As Above	12 ppmvd (Gas, CT on, DB off) 20 ppmvd (Gas, CT and DB on) 30 ppmvd for F.O.
NO_X (CT on, DB off)	DLN, or DLN & SCR for gas WI or SCR for fuel oil 720 Hours on fuel oil with DB On or Off	9 ppmvd (DLN) or 4.5 ppmvd (SCR) for gas 42 ppmvd (WI) or 15 ppmvd (SCR) for fuel oil 12/42 ppmvd (gas/oil) Intermittent Simple Cycle
NO_X (CT and DB on)	DLN & Low NO_X, or DLN & SCR for gas WI & Low NO_X, or SCR for fuel oil Duct burner only fires natural gas	9.4 ppmvd (DLN) or 4.5 ppmvd (SCR) for gas 42 ppmvd (WI) or 15 ppmvd (SCR) for fuel oil DB limited to 0.4 lb/MW-hr

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The Lowest Achievable Emission Rate (LAER) for NO_X is approximately 2 ppmvd. It has been achieved at a small combustion turbine installation using $SCONO_X$. There are permitted projects for large turbines requiring $SCONO_X$ or SCR.
- The "Top" technology in a top/down analysis will achieve 2 ppmvd.
- The Department has reviewed CEMS data from Fort St. Vrain, CO indicating that a similar unit with DLN-2.6 combustors consistently achieved less than 9 ppmvd NO_X in 1997 (obviously with no ammonia slip).[20]
- DLN is a pollution prevention technology. It controls NO_X by not allowing it to form and does not result in emissions of another pollutant (ammonia). The procedures given in the Top/Down methodology allow for cost-effectiveness of further control to be calculated using the pollution prevention technology as the baseline value.
- Starting with a baseline of 9 ppmvd, KUA estimated the cost of SCR to reduce emissions from 9 to 3.5 ppmvd at $5452 per ton assuming 10 ppmvd ammonia slip. KUA estimated cost-effectiveness at $16,056 per ton when the collateral emissions of PM, CO, and ammonia are deducted from the reductions in NO_X emissions. EPA and the Department do not recognize the latter method, although the point is appreciated.
- General Electric estimates that for units designed for fuel oil as stand-by fuel, the costs are much higher than estimated by KUA. They believe that any amount of fuel oil firing will significantly increase costs because heat recovery steam generator maintenance costs will increase. This is due to fouling by sticky ammonium sulfate and bisulfate residue.[21]
- According to estimates by other consultants, the cost of reducing slip from 10 (the basis of KUA's estimate) to 5 or 2 ppmvd would add $600 to 2900 per ton of NO_X removed[22, 23]
- At $6,000 to 8,300 per ton (after adjusting the KUA estimate for slip control), the Department does not believe it is cost-effective to reduce emissions to 3.5 ppmvd with a slip of 2-5 ppmvd

- SCR causes environmental and energy impacts including increased particulate emissions, undesirable (though unregulated) ammonia emissions, and energy penalties. At equal emission rates, DLN technology is a better control strategy than SCR. At higher emission rates, DLN can still be justified as BACT given the cost-effectiveness estimates above together with the negative effects of SCR described above.

- EPA Region IV advised the concerns above are valid. However EPA stated that the Department (in its first draft BACT) did not present "any unusual site-specific conditions associated with the KUA project to indicate that the use of SCR to achieve 3.5 ppmvd would create greater problems than experienced elsewhere at other similar facilities."[24]

- Region IV advised that (notwithstanding cost-effectiveness calculations) it considers SCR cost-effective on the basis that it has been required in many parts of the country without making projects economically unfeasible.[25] EPA advised that it intends to appeal the KUA Permit if the Department does not require a NO_X emissions rate of 3.5 ppmvd when firing natural gas.[26] EPA does not require or propose an ammonia slip limit.

- The Department notes that the EPA Region IV criterion for the BACT limit is most similar to the criterion applied in non-attainment areas where Lowest Achievable Emissions Rate (LAER) is applicable. According to mid-1998 correspondence from EPA Region IX to Goal Line, "any future combustion turbine co-generation project that is subject to the LAER requirement for NO_X must either achieve compliance with a 3.5 ppmv NO_X emission limit, or demonstrate that unique circumstances at the specific facility make compliance with a 3.5 ppmv NO_X emission limit technically infeasible."[27]

- Uncertainties (and statistical variances) in NO_X emissions related to instrumentation, methodology, calibration and sampling errors, exhaust flow, ammonia slip bias, corrections to 15% O_2 and ambient conditions, etc., are approximately equal to "ultra low NO_X" limits (2.5-3.5 ppmvd).[28]

- The Department believes BACT for natural gas firing is 9 ppmvd by DLN or 4.5 ppmvd by SCR (with ammonia slip of 5 ppmvd). The values for the SCR option take into consideration the uncertainties mentioned above and minimize the negative effects of ammonia emissions.

- The recently-drafted Tier I BACT for all large combined cycle turbines prepared by Texas is 9 ppmvd by DLN or 5 ppmvd by SCR (with ammonia slip of 7 ppmvd). The proposal is based on the input from states, applicants, catalyst vendors, turbine manufacturers, etc.

- KUA elected to install SCR technology and meet a 3.5 ppmvd NO_X limit while firing natural gas as required by EPA.[29] The reason is that an appeal would delay issuance of the final permit by roughly one year. KUA has contractual commitments that cannot be met since construction cannot commence until the permit is issued.[30]

- The required NO_X reduction by SCR while firing gas is therefore from 9 to 3.5 ppmvd instead of from 9 to 4.5 ppmvd. More catalyst is normally required to meet the additional 22% reduction to meet EPA's requirement.

- The baseline NO_X limit for fuel oil firing is 42 ppmvd by wet injection. The Department estimates that more catalyst is required to meet the 15 ppmvd NO_X SCR-based limit while firing fuel oil than was required to meet 4.5 ppmvd while firing gas. A unit sized to reduce NO_X from 9 to 4.5 ppmvd while firing gas will only reduce NO_X from 42 to about 27 ppmvd while firing fuel oil. The extra catalyst already required to effect the "additional" 56% reduction to 15 ppmvd while firing fuel oil should be capable of accommodating a revised 3.5 ppmvd gas-based limit while maintaining the specified ammonia slip of 5 ppmvd.

- During intermittent simple cycle operation, the Department will permit NO_X emissions of 12 ppmvd. Prolonged operation of the unit in simple cycle mode will require that it meet the same 9 ppmvd limit by DLN through re-tuning.
- VOC emissions of 1.4 ppm from the combustion turbine by Good Combustion proposed by the Department are at the lower end of values determined as BACT. However even lower values have already been achieved by the previous generation DLN 2 combustors on the GE's 7FA units after tuning. Similar VOC performance is expected with the DLN-2.6 combustors while firing natural gas. The limit of 4 ppm with the duct burner in operation is also low. The 10 ppm limit while firing fuel oil is readily achievable whether the duct burner is on or off.
- The CO concentrations of 12 ppmvd are low with the duct burner off. With the duct burner on, they will be less than 20 ppmvd which is within the range of recent Department BACT determinations for combustion turbines alone. The CO limit, during the limited hours of fuel oil firing, will be set at 30 ppmvd whether or not the duct burner is in operation.
- For reference, CO limits for the Lakeland and Tallahassee projects are 25 ppmvd on gas while the limit for the FPL Fort Myers project is 12 ppmvd. Limits for the Santa Rosa Energy Center are 9 ppmvd with the duct burner off and 24 ppmvd with the large duct burner on. The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, VOC (ozone) or PM_{10}.
- BACT for PM_{10} was determined to be good combustion practices consisting of: inlet air filtering; use of pipeline natural gas; and operation of the unit in accordance with the manufacturer-provided manuals.
- PM_{10} emissions will be very low and difficult to measure. Additionally, the higher emission mode will involve fuel oil firing which will occur substantially less than the permitted 720 hours per year. It is not practical to require running the turbine on oil, simply to conduct tests. Therefore, the Department will set a Visible Emission standard of 10 percent opacity as BACT for both natural gas and fuel oil firing, consistent with the definition of BACT.

COMPLIANCE PROCEDURES

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

BACT EXCESS EMISSIONS APPROVAL

Pursuant to the Rule 62-210.700 F.A.C., the Department through this BACT determination will allow excess emissions as follows: Valid hourly emission rates shall not included periods of startup, shutdown, or malfunction as defined in Rule 62-210.200 F.A.C., where emissions exceed the applicable NO_X standard. These excess emissions periods shall be reported as required in Specific Condition 32 of the Permit . A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart [Rules 62-4.070 F.A.C., 62-210.700 F.A.C. and applicant request].

Excess emissions may occur under the following startup scenarios:

Hot Start: One hour in simple cycle or following a shutdown less than or equal to 8 hours.
Warm Start: Two hours following a shutdown between 8 and 48 hours.
Cold Start: Four hours following a shutdown greater than or equal to 48 hours.

The *starts* are defined by the amount of time the HRSG has been shutdown, following the normal (hot) shutdown procedure described by General Electric, prior to the startup.[31]

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E. Administrator, New Source Review Section
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Department of Environmental Protection
Bureau of Air Regulation
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Recommended By:	Approved By:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Howard L. Rhodes, Director Division of Air Resources Management
Date:	Date:

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Attachment G
Stack Sampling Facilities

The stack sampling facilities were installed in accordance with Rule 62-297.310(6) (attached), as required by Air Construction Permit No. 0310485-004-AC.

A description of the sampling ports follows:

4.0 SAMPLING POINT LOCATION

The sampling point locations and outlet duct schematics are given in Figure 1. Each run consisted of sampling 16 different sample points, a total of 48 points. No O_2 stratification was detected.

(5) Determination of Process Variables.

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

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

(6) Required Stack Sampling Facilities. Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

(a) Permanent Test Facilities. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

(b) Temporary Test Facilities. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

(c) Sampling Ports.

1. All sampling ports shall have a minimum inside diameter of 3 inches.

2. The ports shall be capable of being sealed when not in use.

3. The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

4. For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

5. On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

(d). Work Platforms.

1. Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

2. On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

3. On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

4. All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

(e). Access to Work Platform.

1 Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

2. Walkways over free-fall areas shall be equipped with safety rails and toeboards.

(f). Electrical Power.

1. A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

2. If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

(g). Sampling Equipment Support.

1. A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

a. The bracket shall be a standard 3 inch x 3 inch x one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

b. A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

c. The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

2. A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.

3. When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

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

(a) General Compliance Testing.

1. The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

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

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

a Did not operate; or

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

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

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

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

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

Attachment H
Compliance Test Report

Simple Cycle results is provided. Combined Cycle compliance testing is scheduled for October 18-19, 2001. Results will be provided to FDEP upon report certification.

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REPORT CERTIFICATION

To the best of my knowledge, all applicable field and analytical procedures comply with the Florida Department of Environmental Protection requirements and all test data and plant operating data are true and correct.

SIGNATURE SECURITY SIGNATURE SECURITY

Dagmar Fick, Mechanical Engineer

8/29/2001

Date

2.0 SUMMARY AND DISCUSSION OF RESULTS

CT-3 test results were found to be within the allowable standards of the current permit. Table 1 summarizes the emission results.

Oxides of Nitrogen emissions averaged 8.20 ppmvd @ 15% O_2 and 47.25 lbs/hr, which is within the allowable standard of 9 ppm_{vd} @ 15% O_2 and 65 lbs/hr. Actual CO emissions at 0.17 ppm_{vd} and 0.5 lbs/hr compare well to the permitted values of 12 ppm_{vd} and 43 lbs/hr. VOC emissions averaged 0.06 ppm_{vd} and 0.270 lbs/hr as propane. SO_2 emissions calculated by fuel analysis averaged 0.27 lbs/hr. The fuel analysis of the natural gas stream showed 0.067 grains of Sulfur per 100cubic feet of gas, which is also within the permitted Sulfur content of 20 grains per 100 cubic foot. SO_2 emission calculations are presented in Appendix F along with the fuel analysis and the production data.

Visible emissions, observed concurrently with each compliance run, averaged 0.0 percent opacity for the highest six-minute period of each run (see Appendix D for VE data). Permitted opacity is 10%.

During the test, the heat input rate of the turbine based on the lower heating value (LHV) averaged 1414.4 million btu per hour (MMBTUH) (see Appendix F for calculations).

Complete emission summaries with data logger records and strip chart copies are presented in Appendix B and C.

Table 1. Emission Summary
Unit 3 Combustion Turbine - Gas Fired
Kissimmee Electric Authority
Intercession City, Florida
July 17, 2001

Run Number	Time	Oxygen %	NOx Emissions ppm	NOx ppm 15% O2	NOx ppm @ ISO	NOx lbs/hr	NOx lbs/MMBTU	CO Emissions ppm	CO lbs/hr	CO lbs/MMBTU	C3H8 Emissions as Propane ppm	C3H8 lbs/hr	CT Gas Flow lbs/sec	CT Heat Input MMBTUH HHV	CT Heat Input MMBTUH LHV
Full Load - 160.2 MW															
1	0910-1017	13.87	9.96	8.36	10.64	47.96	0.031	0.29	0.857	0.0006	0.10	0.4720	18.9	1556.7	1408.6
2	1040-1149	13.77	9.91	8.20	10.83	47.08	0.030	0.09	0.259	0.0002	0.03	0.1230	18.5	1558.0	1409.7
3	1208-1317	13.81	9.68	8.05	11.24	46.72	0.030	0.13	0.373	0.0002	0.05	0.2140	18.7	1574.8	1425.0
Average	---	13.82	9.85	8.20	10.90	47.25	0.030	0.17	0.496	0.0003	0.06	0.270	18.7	1563.2	1414.4

Natural Gas Fd-Factor = 8710 MMBTU/dscf
lbs/hr = ppm(2.595 x 10^E-9)MW (20.9/20.9-%O2)(Fd)(Heat Input HHV)
Heat Input HHV = (gas flow)(1041 dry Btu/cf)(3600 sec/hr)/10E6/gas density
MW CO = 28 lbs/lb-mole *MW NOx = 46 lbs/lb-mole* *MW C3H8 = 44.033 lbs/lb-mole*

SO2 Emissions (Subpart GG NSPS) = 0.27 lbs/hr; 0.067 grains/100 cuft per fuel analysis

Allowable Emissions
NOx = 9 ppmvd @ 15%O2 & 65 lbs/hr
CO = 12 ppmvd & 43 lbs/hr
C3H8 = 1.4 ppmvd & 3.0 lbs/hr as VOC
SO2 = 20 grains/100 std. cuft

Attachment I
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 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 NO_x emissions are controlled and stable, 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.

Attachment J
Alternative Methods of Operation

Alternative methods of operation include the use of pipeline quality natural gas and 0.05 percent sulfur NO. 2 or superior grade of fuel oil.

Attachment K
Acid Rain Application