Appendix 1: Current Title V Air Operation Permit 0970043-013-AV

Kissimmee Utility Authority
Cane Island Power Park
Facility ID No. **0970043**
Osceola County

Title V Air Operation Permit Renewal

FINAL Permit No. **0970043-013-AV**

Permitting Authority:
State of Florida
Department of Environmental Protection
Division of Air Resource Management
Bureau of Air Regulation
Permitting South Section

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

Telephone: 850/488-0114
Fax: 850/922-6979

Title V Air Operation Permit Renewal
FINAL Permit No. **0970043-013-AV**

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NOTICE OF FINAL PERMIT RENEWAL

In the Matter of an
Application for Permit Renewal by:

Mr. A. K. Ben Sharma, P.E.
Vice President of Power Supply
Kissimmee Utility Authority
P.O. Box 423219
Kissimmee, FL 34742-3219

Osceola County
FINAL Permit Renewal No. **0970043-013-AV**
Combustion Turbines Units 001-002 and 003
410 MW Power Plant
Cane Island Power Park

Enclosed is FINAL Title V Permit Renewal Number **0970043-013-AV** for the operation of the Cane Island Power Park, located at 6075 Old Tampa Highway, Intercession City, Osceola County, issued pursuant to Chapter 403, Florida Statutes (F.S.).

An electronic version of this permit renewal has been posted on the Division of Air Resource Management's world wide web site for the United States Environmental Protection Agency (U.S. EPA) Region 4 office's review. The web site address is:

http://www.dep.state.fl.us/air/eproducts/ards/default.asp

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the permitting authority.

Executed in Tallahassee, Florida.

Trina L. Vielhauer, Chief
Bureau of Air Regulation

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT RENEWAL (including the FINAL permit renewal) was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 12/27/04 to the person(s) listed or as otherwise noted:

Mr. A. K. Ben Sharma, P.E.*
Mr. Jerome Guidry, P.E., Perigee Technical Services
Mr. Len Kozlov, Central District Office
U.S.EPA, Region 4 (INTERNET E-mail Memorandum)

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency Clerk, receipt of which is hereby acknowledged.

Barbara J. Friday 12/27/04
(Clerk) (Date)

Department of Environmental Protection

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

Jeb Bush
Governor

Colleen M. Castille
Secretary

Permittee:
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, FL 34742

FINAL Permit No. 0970043-013-AV
Facility ID No. 0970043
SIC No.: 49
Project: Title V Air Operation Permit Renewal

This permit renewal is for the operation of the Kissimmee Utility Authority's Cane Island Power Park. This facility is located at 6075 Old Tampa Highway, Intercession City, Osceola County. The UTM coordinates are Zone 17, 449.8 East, and 3127.9 North. The Latitude is 28° 16' 40" North and the Longitude is 81° 31' 01" West.

This Title V air operation permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and Florida Administrative Code (F.A.C.) Chapters 62-4, 62-210, 62-213, and 62-214. The above named permittee is hereby authorized to perform the work and operate the facility shown on the application and approved drawings, plans, and other documents, attached hereto or on file with the permitting authority, in accordance with the terms and conditions of this permit. The facility holds ORIS code **7238** under Phase II of the federal Acid Rain Program.

Referenced attachments made a part of this permit:
Appendix U-1, List of Unregulated Emissions Units and/or Activities
Appendix I-1, List of Insignificant Emissions Units and/or Activities
Table 1-1, Summary of Air Pollutant Standards and Terms
Table 2-1, Summary of Compliance Requirements
Appendix TV-4, Title V Conditions (version dated 02/12/02)
Appendix SS-1, Stack Sampling Facilities (version dated 10/07/96)
Appendix GG, 40 CFR 60 - NSPS Subpart GG for Stationary Gas Turbines
Appendix YYYY, 40 CFR 63 NESHAP - Subpart YYYY for Combustion Turbines
Table 297.310-1, Calibration Schedule (version dated 10/07/96)
Figure 1 - Summary Report-Gaseous And Opacity Excess Emission And Monitoring System Performance Report (version dated 7/96)
Alternate Sampling Procedure, ASP No. 97-B-01
BACT Determination dated April 7, 1993
Order extending permits dated March 18, 1999

Effective Date: January 1, 2005
Renewal Application Due Date: July 5, 2009
Expiration Date: December 31, 2009

Michael G. Cooke, Director
Division of Air Resource Management

Section I. Facility Information.

Subsection A. Facility Description.

This facility is an electric power generating plant and consists of:

Simple-Cycle Combustion Turbine Unit 1 (Emissions Unit 001), rated at 40 MW,

Combined-Cycle Combustion Turbine Unit 2 (Emissions Unit 002), rated at 120 MW, and

Combined-Cycle Combustion Turbine Unit 3 (Emissions Unit 003), rated at 250 MW, with duct burner (Emissions Unit 005).

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

Based on the Title V permit renewal application received June 30, 2004, this facility is a major source of hazardous air pollutants (HAPs).

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

E.U. ID No.	Brief Description
001	Simple-Cycle Combustion Turbine (Unit 001), rated at 40 MW, 367 mmBtu/hr for natural gas and 372 mmBtu/hr for number 2 fuel oil, capable of burning natural gas and number 2 fuel oil, with emissions exhausted through a 65 ft. stack .
002	Combined-Cycle Combustion Turbine (Unit 002), rated at 120 MW, 869 mmBtu/hr for natural gas and 928 mmBtu/hr for number 2 fuel oil, capable of burning natural gas and number 2 fuel oil, with emissions exhausted through a 75 ft. stack .
003 005	Combined-Cycle Combustion Turbine (Unit 003), with duct burner (Unit 005).
004	Fuel Storage Tank (one million gallon)(Unit 004).

Unregulated Emissions Units and/or Activities	
007	Distillate Fuel Oil Tank No. 2 (700,000 gal. capacity)
008	Distillate Fuel Oil Tank No. 1 (300,000 gal. capacity)
006	Cooling Tower

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

Subsection C. Relevant Documents.

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

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

These documents are on file with the permitting authority:
Initial Title V Permit Application received June 14, 1996 and subsequent applications for revisions received on June 6, 2000, October 17, 2001 and July 15, 2002 (withdrawn).
Acid Rain Phase II Part Application renewal signed by the Designated Representative on June 28, 2004.
Title V Permit Renewal Application received on June 30, 2004.
DRAFT Title V Permit Renewal clerked on September 23, 2004.
PROPOSED Title V Permit Renewal posted on November 8, 2004.

Section II. Facility-wide Conditions.

The following conditions apply facility-wide:

1. APPENDIX TV-4, TITLE V CONDITIONS, is a part of this permit.
{Permitting note: APPENDIX TV-4, TITLE V CONDITIONS, is distributed to the permittee only. Other persons requesting copies of these conditions shall be provided a copy when requested or otherwise appropriate.}

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

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

4. Prevention of Accidental Releases (Section 112(r) of CAA).
a. The permittee shall submit its Risk Management Plan (RMP) to the Chemical Emergency Preparedness and Prevention Office (CEPPO) RMP Reporting Center when, and if, such requirement becomes applicable. Any Risk Management Plans, original submittals, revisions or updates to submittals, should be sent to:

RMP Reporting Center
Post Office Box 1515
Lanham-Seabrook, Maryland 20703-1515
Telephone: 301/429-5018

and,

b. The permittee shall submit to the permitting authority Title V certification forms or a compliance schedule in accordance with Rule 62-213.440(2), F.A.C.
[40 CFR 68]

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

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

7. [Reserved.]

8. Not federally enforceable. General Pollutant Emission Limiting Standards. Volatile Organic Compounds (VOC) Emissions or Organic Solvents (OS) Emissions. The permittee shall allow no person to store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds (VOC) or organic solvents (OS) without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. {Permitting Note: No vapor emissions control devices or systems are deemed necessary nor ordered by the Department as of the issuance date of this permit.}
[Rule 62-296.320(1)(a), F.A.C.]

9. Emissions of Unconfined Particulate Matter. Pursuant to Rules 62-296.320(4)(c)1., 3. & 4., F.A.C., reasonable precautions to prevent emissions of unconfined particulate matter at this facility include the following requirements (see Condition 57. of APPENDIX TV-4, TITLE V CONDITIONS.

The following techniques will be used to prevent unconfined particulate matter emissions on as needed basis:

a. Maintenance of paved areas shall be performed as needed.
b. Worker and site vehicle movements shall be conducted on paved roads.
c. Delivery vehicle movements shall be conducted on paved roads.
d. Fuel oil delivery by truck shall be conducted on paved roads.

[Rule 62-296.320(4)(c)2., F.A.C.; and proposed by applicant in the initial Title V permit application received June 14, 1996.]

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

11. Statement of Compliance. The annual statement of compliance pursuant to Rule 62-213.440(3)(a)2., F.A.C., shall be submitted to the Department and EPA within 60 (sixty) days after the end of the calendar year using DEP Form No. 62-213.900(7), F.A.C.
[Rules 62-213.440(3) and 62-213.900, F.A.C.]

{Permitting Note: This condition implements the requirements of Rules 62-213.440(3)(a)2. & 3., F.A.C. (see Condition 51. of APPENDIX TV-4, TITLE V CONDITIONS)}

12. State Compliance Authority. The permittee shall submit all compliance related notifications and reports required of this permit to the Department's Central District office:

Central District Office
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767

Telephone: 407/894-7555
Fax: 407/897-2966

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

United States Environmental Protection Agency, Region 4
Air Pesticides & Toxics Management Division
Air & EPCRA Enforcement Branch
Air Enforcement Section
61 Forsyth Street
Atlanta, Georgia 30303-8960

Telephone: 404/562-9155
Fax: 404/562-9163 or 404/562-9164

14. Certification by Responsible Official (RO). In addition to the professional engineering certification required for applications by Rule 62-4.050(3), F.A.C., any application form, report, compliance statement, compliance plan and compliance schedule submitted pursuant to Chapter 62-213, F.A.C., shall contain a certification signed by a responsible official that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. Any responsible official who fails to submit any required information or who has submitted incorrect information shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary information or correct information.
[Rule 62-213.420(4), F.A.C.]

12.

Section III. Emissions Unit(s) and Conditions.

Subsection A. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
001	Simple-Cycle Combustion Turbine (Unit 001), rated at 40 MW, 367 mmBtu/hr for natural gas and 372 mmBtu/hr for number 2 fuel oil, capable of burning any combination of natural gas and number 2 fuel oil, with emissions exhausted through a 65 ft. stack.

This emissions unit is regulated under Acid Rain, Phase II; Rule 62-210.300, F.A.C., Permits Required; and is subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines (attached as Appendix GG). This unit underwent a BACT Determination dated April 7, 1993. BACT Limits were incorporated into the subsequent air construction/PSD permits including AC 49-205703 (PSD-FL-182) issued on April 9, 1993. Since this unit is located at a major source for hazardous air pollutants, this unit is also subject to 40 CFR 63, Subpart YYYY, National Emissions Standards for Hazardous Air Pollutants for Combustion Turbines (attached as Appendix YYYY). See Specific Conditions **C.16** and **C.17**.

{Permitting Note. Fossil fuel fired combustion turbine Unit 001 is a 40 MW GE Model LM6000PA. NO_x emissions are controlled by low-NO_x combustors, and by water injection, whereas SO_2 and H_2SO_4 emissions are controlled by firing .05% S oil, for only limited time periods. Unit 001 began commercial operation in 1994.}

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

Essential Potential to Emit (PTE) Parameters

A.1. Permitted Capacity. The maximum operation heat input rates are as follows:

Unit No.	mmBtu/hr Heat Input	Fuel Type
001	367* 372*	Natural Gas Fuel Oil

*Based on 101.3 kilopascals pressure, 288 Kelvin and 60% relative humidity (ISO standard day conditions), and lower heating value of the fuel fired.

[Rules 62-4.160(2) and 62-210.200(PTE), F.A.C.; AC 49-205703 (PSD-FL-182); 0970043-007-AC (modification of PSD-FL-182A)]

A.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **C.8.** [Rule 62-297.310(2), F.A.C.]

A.3. Methods of Operation - Fuels. The only fuels allowed to be fired are pipeline-quality natural gas and low sulfur No. 2 distillate oil. The sulfur content of the No. 2 distillate oil shall not exceed 0.05% sulfur by weight. Operation of Unit No. 1 shall not exceed 5000 hours during any consecutive 12 months. Of the total allowable hours of operation, Unit No. 1 shall fire distillate oil for no more than:

a. 800 hours during any consecutive 12 months if natural gas is available, or
b. 1000 during any consecutive 12 months if natural gas is unavailable.

{Permitting Note: The limitations of specific conditions A.3 and A.6 are more stringent than the NSPS sulfur dioxide limitation and thus assure compliance with 40 CFR 60.333 and 60.334}
[Rule 62-213.410, F.A.C., AC 49-205703 (PSD-FL-182); 0970043-007-AC (PSD-FL-182A); 0970043-009-AV, Revised on 10/13/00]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **A.4.** through **A.5.** are based on the specified averaging time of the applicable test method.}

A.4. Visible Emissions. Visible emissions shall not exceed 10 percent opacity, except for during startup, shutdown or periods of part load operation, at which time visible emissions shall not exceed 20 percent opacity.
[AC 49-205703 (PSD-FL-182)]

A.5. The maximum allowable emissions from Unit 001 shall not exceed the emission limitations listed below.

Pollutant	Emission Limits			Basis
	Gas	Number 2 Fuel Oil	Equivalent Emissions Tons/Year [a, b]	
NO_x [c]	25 ppmvd at 15% oxygen on a dry basis	42 ppmvd at 15% oxygen on a dry basis	105.5 [c]	BACT
SO_2	nil	20 lb/hr	10.0	BACT
PM	0.0245lb/mmBtu	0.0323 lb/mmBtu	24.0	BACT
H_2SO_4	nil	2.2 lb/hr	1.1	BACT
VOC	1.4 lb/hr	3 lb/hr	4.3	BACT
CO	30 ppmvd	63 ppmvd	118.0	BACT
Opacity	10% (see A.4.)	10% (see A.4.)		BACT
Be [d]	nil	2.5 E-6 lb/MMBtu	< 1	BACT
As [d]	nil	4.2 E-6 lb/MMBtu	< 1	AC 49-205703
Hg [d]	nil	3.1 E-6 lb/MMBtu	< 1	AC 49-205703
Pb [d]	nil	2.8 E-5 lb/MMBtu	< 1	AC 49-205703

a. Tons per year based on 4000 hrs/yr for natural gas firing, 1000 hrs/yr for number 2 fuel oil firing.
b. Based on 372 mmBtu/hr for number 2 fuel oil and 367 mmBtu/hr for natural gas.
c. Original permit PSD-FL-182 limited NOx emissions to 25 ppmvd for gas firing to be reduced to 15 ppmvd. Project No. 0970043-007-AC (12/21/99) modified the PSD permit establishing the final NO_x emission limit as 25 ppmvd when firing natural gas with a corresponding reduction in hours of operation (5000 hours per year) and a combined NOx emissions cap (366.1 TPY) with Unit No. 2.
d. Limits based upon an approved emission factor, which is subject to change in the future.

[AC49-205703 (PSD-FL-182); 0970043-007-AC; 0970043-009-AV, Revised on 10/13/00]

Test Methods and Procedures

A.6. Annual Compliance Tests. Emission testing for visible emissions and NO_x shall be performed annually, in accordance with specific condition **A.8.**, with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using the following EPA reference methods in accordance with 40 CFR 60, Appendix A:

a. Method 9 for VE;
b. Method 20 for NO_x.

Annual compliance with the NO_x standard may be determined by using data collected as part of the annual Relative Accuracy Test Audit (RATA) testing as described in 40 CFR 60 Appendix B. Performance Specification 2. Section 7.1.2. instead of performing Methods 7E and 20 as separate tests. EPA Method 10 will be conducted simultaneously with the NO_x/ O_2 RATA tests. The 20-30 minute tests conducted for the RATA testing will be strung together in a manner that fulfills additional requirements of EPA Methods 10 and 20 as to test run time (3 one hour runs) and O_2 stratification investigation. The collected data will be bias corrected to comply with the RATA test requirements, but will not be bias corrected for compliance with NSPS so as to meet the requirements of methods 10 and 20 (the NSPS test methods). No less than eight test points will be used for the RATA testing which will comply with both the RATA test requirements and the NSPS test requirements. The NO_x span for methods 20 and 7E should not exceed 50 ppm instead of a span of 300 ppm as required by Subpart GG. Mass emissions of NO_x and CO shall be determined pursuant to the procedures in 40 CFR 60, Appendix A. Method 19 or 40 CFR 75, Appendix F. If the unit is not operating because of scheduled maintenance outages and emergency repairs, it will be tested within thirty days of returning to service.
Note: Measured NO_x emissions will be ISO corrected for comparison with NSPS, but will not be ISO corrected for comparison with the BACT standard.
[Rules 62-297.401 and 62-213.440, F.A.C., and AC 49-205703 (PSD-FL-182)]

A.7. Testing for PM, CO, VOC. Particulate matter tests shall be conducted using EPA test methods 5 or 17. Alternatively, the opacity emissions test may be used unless the 10% opacity limit is exceeded. Carbon monoxide tests shall be conducted using EPA test method 10. VOC tests shall be conducted using EPA test method 25A.
[Rule 62-297.401, F.A.C., and AC 49-205703 (PSD-FL-182).]

A.8. Additional Test Requirements. Test results shall be the average of three valid runs. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity, which is defined as 95-100 percent of the maximum heat input rate allowed by this permit, achievable for the average ambient air temperature during the test. If it is impracticable to test at permitted capacity, the emissions unit may be tested at less than permitted capacity. In such cases, subsequent operation is limited by adjusting downward the entire heat input vs. inlet temperature curve by the increment equal to the difference between the maximum permitted heat input value and 105 percent of the value reached during the test. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Data, curves, and calculations necessary to demonstrate the heat input rate correction at both design and test conditions shall be submitted to the Department with the compliance test report.
[AC 49-205703 (PSD-FL-182).]

A.9. Sulfur Dioxide - Sulfur Content. The permittee shall demonstrate compliance with the SO_2 limit by EPA test method 8 or fuel sampling and analysis. The permittee shall demonstrate compliance with the gaseous fuel sulfur limit via record keeping. Excess emissions shall be reported if the fuel being fired in the gas turbine exceeds 0.05% sulfur, by weight.

[AC 49-205703 (PSD-FL-182).]

A.10. Fuel Sampling & Analysis - Sulfur/Nitrogen and Lower Heating Value. The following fuel sampling and analysis program shall be used to demonstrate compliance with the sulfur dioxide standard:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest editions, to analyze a representative sample of the blended fuel following each fuel delivery. ASTM D3246-81, or its latest edition, shall be used for sulfur content of gaseous fuel.

b. Record daily the amount of each fuel fired, density of each fuel, heating value, nitrogen content and the percent sulfur content by weight of fuel oil as specified in 40 CFR 60.334.

[Rule 62-213.440, F.A.C.; and AC 49-205703 (PSD-FL-182).]

Monitoring of Operations

A.11. Continuous Monitoring Required. A continuous monitoring system shall be maintained to record fuel consumption. A continuous monitoring system shall be maintained to record emissions of nitrogen oxides in accordance with the requirements of 40 CFR 75. Data collected from this system shall be used for periodic monitoring purposes. While water injection is being utilized for NO_x control, water to fuel ratio and fuel bound nitrogen is not required to be continuously monitored as long as the permittee will report excess emissions using the data collected by the continuous monitoring system in accordance with the following conditions:

1. Each NO_x CEMS must be capable of calculating NO_x emissions concentrations corrected to 15% O2 and ISO conditions.
2. Monitor data availability shall be no less than 95 percent on a quarterly basis.
3. NO_x CEMS should provide at least 4 data points for each hour and calculate a one-hour average.

To implement condition 1, Kissimmee Utility Authority (KUA) shall use ambient data (temperature, relative humidity, pressure) to correct excess emissions data to ISO conditions if requested by the Department. If monitor availability drops below 95% on a quarterly basis as prescribed in condition 2, KUA shall use water to fuel ratio and fuel-bound nitrogen data to monitor excess emissions in subsequent quarters until the minimum CEMS monitor availability is above 95%. The use of CEMS to monitor excess emissions is more stringent than the surrogate parameter monitoring in 40 CFR 60.334 since the CEMS directly measures NO_x emissions. The CEMS also provides monitoring when no water injection is used to control NOx emissions (i.e., when firing natural gas, dry low NO_x burners are used).

[AC 49-205703 (PSD-FL-182).]

A.12. Excess Emissions by CEMS. The CEMS shall be used to determine periods of excess emissions as per 40 CFR 60.334. Excess emissions are defined for this emissions unit as any 60-minute period during which the average emissions exceed the emission limits of specific condition **A.5.** of this permit. Periods of startup, shutdown and malfunction shall be monitored, recorded and reported with excess emissions following the format and requirements of 40 CFR 60.7.

[AC 49-205703 (PSD-FL-182).]

Recordkeeping and Reporting Requirements

A.13. Excess Emission Reports. Semi-annual excess emission reports shall be submitted to the DEP's Central District Office. These reports shall be postmarked by the 30th day following the end of each calendar half. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.
[AC 49-205703 (PSD-FL-182)]

A.14. Natural Gas Sulfur Content Records Required. The owner or operator shall receive and maintain records of sulfur content of natural gas provided by the natural gas supplier, as per 40 CFR 60.334. The records shall report total sulfur content in terms of grains of sulfur per hundred cubic feet (standard conditions).
[AC 49-205703 (PSD-FL-182)]

A.15. Additional Reports Required. The owner or operator shall report the following with the Annual Operating Report (AOR) by March 1 of each calendar year: sulfur and nitrogen contents, by weight, and lower heating value of the fuel oil being fired, annual fuel consumption of number 2 fuel oil and natural gas, hours of operation per fuel usage and air emission limits. As it may become available, the permittee shall also provide the Department with information regarding documented enhancements to the LM6000PA, dual-fuel class, combustion turbine machine, which have demonstrated in the field the ability to achieve a continuous NO_X emission rate of 15 ppmvd while firing natural gas.
[Rule 62-210.370(3), F.A.C.; and AC49-205703 (PSD-FL-182); 0970043-007-AC; 0970043-009-AV, Revised on 10/13/00]

Other Specific Conditions

A.16. Maintain Capability to install an SCR. This emissions unit is permitted for maximum NO_x emission levels of 15 (gas)/42 (oil) ppmv. The Department will revise permitted emission levels for NO_x if the manufacturer achieves an even lower NO_x emission, pursuant to F.A.C. Rule 62-4.080. The permittee shall maintain capability for future installation of a selective catalytic reduction (SCR) system. This is required in the event that the permittee is unable to comply with the permitted NO_x levels and the Department requires an SCR to be installed. In the event an SCR system is required to be installed, the emission limitations shall be established at the time of installation by stack test results and through a revised determination of BACT.
[AC 49-205703 (PSD-FL-182)]

A.17. This emissions unit is also subject to conditions **C.1.** through **C.17.,** contained in **Subsection C., Common Conditions.**

A.18. This emissions unit is also subject to conditions **D.1.** through **D.6.,** contained in **Subsection D., NSPS Common Conditions.**

Subsection B. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
002	Combined-Cycle Combustion Turbine (Unit 002), rated at 120 MW, 869 mmBtu/hr for natural gas and 928 mmBtu/hr for number 2 fuel oil, capable of burning any combination of natural gas and number 2 fuel oil, with emissions exhausted through a 75 ft. stack.

This emissions unit is regulated under Acid Rain, Phase II; Rule 62-210.300, F.A.C., Permits Required; and, is subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines. The affected facility to which this subpart applies is the combined-cycle gas turbine, Unit 2. This unit underwent a BACT Determination dated April 7, 1993. BACT limits were incorporated into the subsequent air construction/PSD permits including AC 49-205703 (PSD-FL-182) issued on April 9, 1993. Since this unit is located at a major source for hazardous air pollutants, this unit is also subject to 40 CFR 63, Subpart YYYY, National Emissions Standards for Hazardous Air Pollutants for Combustion Turbines (attached as Appendix YYYY). See Specific Conditions **C.16** and **C.17**.

{Permitting Notes: Fossil fuel fired combustion turbine Unit 002 is a General Electric Model PG7111EA. NO_x emissions are controlled by low-NO_x combustors, and by water injection, whereas SO_2 and H_2SO_4 emissions are controlled by firing 0.05%, by weight, sulfur oil for only limited time periods. Exhaust is vented through the heat recovery steam generator that is not equipped with duct burners and then through a 75 ft. stack. The turbine exhaust may also be vented through a bypass stack for simple-cycle operation when the HRSG or steam turbine is down for maintenance and/or repair. The turbine began commercial operation in 1995.}

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

Essential Potential to Emit (PTE) Parameters

B.1. Permitted Capacity. The maximum operation heat input rates are as follows:

Unit No.	mmBtu/hr Heat Input	Fuel Type
002	869*	Natural Gas
	928*	No. 2 Fuel Oil

* Based on 101.3 kilopascals pressure, 288 Kelvin and 60% relative humidity (ISO standard day conditions), and lower heating value of the fuel fired.

[Rules 62-4.160(2), 62-210.200(PTE), F.A.C.; and AC 49-205703 (PSD-FL-182)]

B.2. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **C.8.**
[Rule 62-297.310(2), F.A.C.]

B.3. Methods of Operation.

a. Fuels: The only fuel(s) allowed to be burned are natural gas and number 2 fuel oil (0.05%), except that firing of number 2 fuel oil is limited to no more than 1000 hours per year if natural gas is unavailable, or no more than 800 hours per year if gas is available. The sulfur content of the fuel oil shall not exceed 0.05%, by weight. {Permitting Note: The limitations of specific conditions A.3 and A.6 are more stringent than the NSPS sulfur dioxide limitation and thus assure compliance with 40 CFR 60.333 and 60.334}

b. Inlet Air Fogging: The permittee is authorized to install and operate a high pressure, direct water spray fogging system. The proposed equipment will inject up to 26 gpm from spray nozzles to provide evaporative cooling of the compressor inlet air to Unit 2. Based on an inlet air mass flow rate of 2,077,077 pounds per hour, the inlet air fogging system shall be designed to achieve a

25° F cooling reduction from an ambient temperature of 95° F to cooled compressor inlet air temperature of 70° F. {Permitting Note: The inlet air fogging system will typically operate during periods of peak power demand and high ambient temperatures. Fogging provides evaporative cooling of the inlet air to the compressor, which allows a higher mass flow rate with a corresponding increase in power production of up to 8 MW depending on initial ambient conditions. The increased power production is realized by firing additional fuel, which results in increased actual emissions. However, there are no increases in the maximum heat input rates, power production, or emissions levels, which are established under the coldest expected ambient temperatures. Fogging simply allows performance of the combustion turbine at a lower temperature than the existing ambient conditions.}
[Rule 62-213.410, F.A.C.; AC 49-205703 (PSD-FL-182); 0970043-008-AC (PSD-FL-182I); and 0970043-009-AV, Revised on 10/13/00]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **B.4.** through **B.5.** are based on the specified averaging time of the applicable test method.}

B.4. Visible Emissions. Visible emissions shall not exceed 10 percent opacity, except for during startup, shutdown or periods of part load operation, at which time visible emissions shall not exceed 20 percent opacity.
[AC 49-205703 (PSD-FL-182)]

B.5. The maximum allowable emissions from Unit 2 shall not exceed the emission limitations listed below.

Pollutant	Emission Limits			Basis
	Gas	Number 2 Fuel Oil	Equivalent Emissions Tons/Year [a, b]	
NO_x [c]	15 ppmvd at 15% oxygen on a dry basis	42 ppmvd at 15% oxygen on a dry basis	290.6	BACT
SO_2	nil	52 lb/hr	26	BACT
PM	0.010 lb/mmBtu	0.0162 lb/mmBtu	41.2	BACT
H_2SO_4	nil	5.72 lb/hr	2.86	BACT
VOC	2 lb/hr	5 lb/hr	10.26	BACT
CO	20 ppmvd	20 ppmvd	242	BACT
Opacity	10% (see B.4.)	10% (see B.4.)		BACT
Be [d]	nil	2.5e-6 lb/mmBtu	< 1	BACT
As [d]	nil	4.2e-6 lb/mmBtu	< 1	AC 49-205703
Hg [d]	nil	3.0e-6 lb/mmBtu	< 1	AC 49-205703
Pb [d]	nil	2.8e-5 lb/mmBtu	< 1	AC 49-205703

a. Tons per year based on 7760 hrs/yr for natural gas firing, 1000 hrs/yr for number 2 fuel oil firing.
b. Based on 928 mmBtu/hr for number 2 fuel oil and 869 mmBtu/hr for natural gas.
c. NO_x emission limits were permitted to be 25 ppmvd while firing natural gas until 1/1/98 via original application.
d. Limits based upon an approved emission factor, which is subject to change in the future.

B.6. Annual Compliance Tests. Emission testing for visible emissions and NO_x shall be performed annually, in accordance with specific condition **B.8.**, with the fuel(s) used for more than 400 hours

in the preceding 12-month period. Tests shall be conducted using the following EPA reference methods in accordance with 40 CFR 60, Appendix A:

a. Method 9 for VE;
b. Method 20 for NO_x.

Annual compliance with the NO_x standard may be determined by using data collected as part of the annual Relative Accuracy Test Audit (RATA) testing as described in 40 CFR 60 Appendix B. Performance Specification 2. Section 7.1.2. instead of performing Methods 7E and 20 as separate tests. EPA Method 10 will be conducted simultaneously with the NO_x/ O_2 RATA tests. The 20-30 minute tests conducted for the RATA testing will be strung together in a manner that fulfills additional requirements of EPA Methods 10 and 20 as to test run time (3 one hour runs) and O_2 stratification investigation. The collected data will be bias corrected to comply with the RATA test requirements, but will not be bias corrected for compliance with NSPS so as to meet the requirements of methods 10 and 20 (the NSPS test methods). No less than eight test points will be used for the RATA testing which will comply with both the RATA test requirements and the NSPS test requirements. The NO_x span for methods 20 and 7E should not exceed 50 ppm instead of a span of 300 ppm as required by Subpart GG. Mass emissions of NO_x and CO shall be determined pursuant to the procedures in 40 CFR 60, Appendix A. Method 19 or 40 CFR 75, Appendix F. If the unit is not operating because of scheduled maintenance outages and emergency repairs, it will be tested within thirty days of returning to service.
Note: Measured NO_x emissions will be ISO corrected for comparison with NSPS, but will not be ISO corrected for comparison with the BACT standard.
[Rules 62-297.401 and 62-213.440, F.A.C.; and AC 49-205703 (PSD-FL-182)]

B.7. Testing for PM, CO, VOC. Particulate matter tests shall be conducted using EPA test methods 5 or 17. Alternatively, the opacity emissions test may be used unless the 10% opacity limit is exceeded. Carbon monoxide tests shall be conducted using EPA test method 10. VOC tests shall be conducted using EPA test method 25A.
[Rule 62-297.401, F.A.C.; and AC 49-205703 (PSD-FL-182)]

B.8. Additional Test Requirements. Test results shall be the average of three valid runs. Testing of emissions shall be conducted with the emissions unit operating at permitted capacity, which is defined as 95-100 percent of the maximum heat input rate allowed by this permit, achievable for the average ambient air temperature during the test. If it is impracticable to test at permitted capacity, the emissions unit may be tested at less than permitted capacity. In such cases, subsequent operation is limited by adjusting downward the entire heat input vs. inlet temperature curve by the increment equal to the difference between the maximum permitted heat input value and 105 percent of the value reached during the test. Once the emissions unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity. Data, curves, and calculations necessary to demonstrate the heat input rate correction at both design and test conditions shall be submitted to the Dept. with the compliance test report.
[AC 49-205703 (PSD-FL-182)]

B.9. The permittee shall demonstrate compliance with the SO_2 limit by EPA test method 8 or fuel sampling and analysis. The permittee shall demonstrate compliance with the gaseous fuel sulfur limit via record keeping. Excess emissions shall be reported if the fuel being fired in the gas turbine exceeds 0.05% sulfur by weight.
[AC 49-205703 (PSD-FL-182)]

B.10. Fuel Sampling & Analysis - Sulfur/Nitrogen and Lower Heating Value. The following fuel sampling and analysis program shall be used to demonstrate compliance with the sulfur dioxide standard:

a. Determine and record the as-fired fuel sulfur content, percent by weight, for liquid fuels using either ASTM D2622-92, ASTM D4294-90, both ASTM D4057-88 and ASTM D129-91, or the latest editions, to analyze a representative sample of the blended fuel following each fuel delivery. ASTM D3246-81, or its latest edition, shall be used for sulfur content of gaseous fuel.

b. Record daily the amount of each fuel fired, density of each fuel, heating value, nitrogen content and the percent sulfur content by weight of fuel oil as specified in 40 CFR 60.334.

[Rule 62-213.440, F.A.C.; and AC 49-205703 (PSD-FL-182)]

Monitoring of Operations

B.11 Continuous Monitoring Required. A continuous monitoring system shall be maintained to record fuel consumption. A continuous monitoring system shall be maintained to record emissions of nitrogen oxides in accordance with the requirements of 40 CFR 75. Data collected from this system shall be used for periodic monitoring purposes. While water injection is being utilized for NO_x control, water to fuel ratio and fuel bound nitrogen is not required to be continuously monitored as long as the permittee will report excess emissions using the data collected by the continuous monitoring system in accordance with the following conditions:

1. Each NO_x CEMS must be capable of calculating NO_x emissions concentrations corrected to 15% O2 and ISO conditions.
2. Monitor data availability shall be no less than 95 percent on a quarterly basis.
3. NO_x CEMS should provide at least 4 data points for each hour and calculate a one-hour average.

To implement condition 1, KUA shall use ambient data (temperature, relative humidity, pressure) to correct excess emissions data to ISO conditions if requested by the Department. If monitor availability drops below 95% on a quarterly basis as prescribed in condition 2, KUA shall use water to fuel ratio and fuel-bound nitrogen data to monitor excess emissions in subsequent quarters until the minimum CEMS monitor availability is above 95%. The use of CEMS to monitor excess emissions is more stringent than the surrogate parameter monitoring in 40 CFR 60.334 since the CEMS directly measures NO_x emissions. The CEMS also provides monitoring when no water injection is used to control NOx emissions (i.e., when firing natural gas, dry low NO_x burners are used).

[AC 49-205703 (PSD-FL-182)]

B.12. Excess Emissions by CEMS. The CEMS shall be used to determine periods of excess emissions as per 40 CFR 60.334. Excess emissions are defined for this emissions unit as any 60-minute period during which the average emissions exceed the emission limits of specific condition **B.5.** of this permit. Excess emissions from the combustion turbine caused entirely or in part by the operation of the inlet air fogging system shall also be prohibited. Periods of startup, shutdown and malfunction shall be monitored, recorded and reported with excess emissions following the format and requirements of 40 CFR 60.7.

[AC49-205703 (PSD-FL-182); 0970043-008-AC (PSD-FL-182I); and 0970043-009-AV, Revised on 10/13/00]

Recordkeeping and Reporting Requirements

B.13. Excess Emission Reports. Semi-annual excess emission reports shall be submitted to the DEP's Central District Office. These reports shall be postmarked by the 30th day following the

last day of June and the last day of December. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334.
[AC 49-205703 (PSD-FL-182)]

B.14. Natural Gas Sulfur Content Records Required. The owner or operator shall receive and maintain records of sulfur content of natural gas provided by the natural gas supplier, as per 40 CFR 60.334. The records shall report total sulfur content in terms of grains of sulfur per hundred cubic feet (standard conditions).
[AC 49-205703 (PSD-FL-182)]

B.15. Additional Reports Required. The owner or operator shall report the following with the Annual Operating Report (AOR) by March 1 of each calendar year: sulfur and nitrogen contents, by weight, and lower heating value of the fuel oil being fired, annual fuel consumption of number 2 fuel oil and natural gas, hours of operation per fuel usage and air emission limits.
[Rule 62-210.370(3), F.A.C.; and AC 49-205703 (PSD-FL-182)]

Other Conditions

B.16. Maintain Capability to install an SCR. This emissions unit is permitted for maximum NO_x emission levels of 15 (gas)/42 (oil) ppmv. The Department will revise permitted emission levels for NO_x if the manufacturer achieves an even lower NO_x emission, pursuant to F.A.C. Rule 62-4.080. The permittee shall maintain capability for future installation of a selective catalytic reduction (SCR) system. This is required in the event that the permittee is unable to comply with the permitted NO_x levels and the Department requires an SCR to be installed. In the event an SCR system is required to be installed, the emission limitations shall be established at the time of installation by stack test results and through a revised determination of BACT.
[AC 49-205703 (PSD-FL-182)]

B.17. This emissions unit is also subject to conditions **C.1.** through **C.17,** contained in **Subsection C., Common Conditions.**

B.18. This emissions unit is also subject to conditions **D.1.** through **D.6.,** contained in **Subsection D., NSPS Common Conditions.**

Subsection C. Common Conditions.

E.U. ID No.	Brief Description
001	Simple-Cycle Combustion Turbine (Unit 001), rated at 40 MW, 367 mmBtu/hr for natural gas and 372 mmBtu/hr for number 2 fuel oil, capable of burning any combination of natural gas and number 2 fuel oil, with emissions exhausted through a 65 ft. stack. GE Model LM6000PA.
002	Combined-Cycle Combustion Turbine (Unit 002), rated at 120 MW, 869 mmBtu/hr for natural gas and 928 mmBtu/hr for number 2 fuel oil, capable of burning any combination of natural gas and number 2 fuel oil, with emissions exhausted through a 75 ft. stack. GE Model PG7111EA.
003 005	Combined-Cycle Combustion Turbine (Unit 003), with duct burner (Unit 005), rated at 250 MW, 1696 mmBtu/hr for natural gas and 1910 mmBtu/hr for number 2 fuel oil, and capable of burning any combination of natural gas and number 2 fuel oil. Emissions are exhausted through a 100 ft. stack for simple-cycle operation, and a 130 ft. stack for combined-cycle operation. GE Model MS7241FA.

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

Essential Potential to Emit (PTE) Parameters

C.1. Restricted Operation. Unit No. 1 shall operate no more than 5000 hours during any consecutive 12 months. Operation of Unit No. 2 is not restricted (8,760 hours/year). In addition, the combined NOx emissions of Unit Nos. 1 and 2 shall not exceed 366.1 tons during any consecutive 12 months. Compliance with this requirement shall be demonstrated each month with NOx emissions data collected from the installed CEMS. Records shall be maintained on site demonstrating compliance with this cap for each consecutive 12-month period. Additionally, the annual submittal of each Annual Operating Report shall include such data and calculations. {Permitting Note: Revised by Project No. 0970043-009-AV on 10/13/00 to incorporate previous Project No. 0970043-007-AC that modified original permit PSD-FL-182. This action set a final NOx limit for Unit No. 1 of 25 ppmvd with a corresponding reduction in annual hours of operation from 8760 to 5000 and established the NOx emissions cap.}
[Rule 62-210.200(PTE), F.A.C.; 0970043-007-AC (PSD-FL-182A); 0970043-009-AV, Revised on 10/13/00.]

Emission Limitations and Standards

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

Excess Emissions

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

C.2. Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing:

(1) best operational practices to minimize emissions are adhered to and
(2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration.

[Rule 62-210.700(1), F.A.C.]

C.3. Excess emissions which are caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure which may reasonably be prevented during startup, shutdown or malfunction shall be prohibited.
[Rule 62-210.700(4), F.A.C.]

Monitoring of Operations

C.4. Determination of Process Variables.
(a) Required Equipment. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.
(b) Accuracy of Equipment. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.
[Rule 62-297.310(5), F.A.C.; and PSD-FL-254, Specific Condition 50.]

C.5. Visible Emissions. The test method for visible emissions for emissions units 001 (Unit 1), 002 (Unit 2), and 003 (Unit 3) shall be EPA Method 9, adopted and incorporated by reference in Rule 62-204.800, F.A.C., and referenced in Chapter 62-297, F.A.C.
[Rules 62-204.800 and 62-297.401, F.A.C.]

C.6. Required Number of Test Runs. For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five day period allowed for the test, the Secretary or his or her designee may accept the results of the two complete runs as proof of compliance, provided that the arithmetic mean of the results of the two complete runs is at least 20 percent below the allowable emission limiting standards.
[Rule 62-297.310(1), F.A.C.]

C.7. Calculation of Emission Rate. The indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the separate test runs unless otherwise specified in a particular test method or applicable rule.
[Rule 62-297.310(3), F.A.C.]

C.8. Operating Rate During Testing. Testing of emissions shall be conducted with each emissions unit operation at permitted capacity, which is defined as 95 to 100 percent of the maximum operation rate allowed by the permit. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the minimum permitted capacity; in this case, subsequent emissions unit operation is limited to 105 percent of the test load until a new test is conducted. Once the emissions unit is so limited, operation at higher capacities is allowed for no

more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
[Rule 62-297.310(2), F.A.C.]

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

C.10. Required Stack Sampling Facilities. When a mass emissions stack test is required, the permittee shall comply with the requirements contained in Appendix SS-1, Stack Sampling Facilities, attached to this permit.
[Rule 62-297.310(6), F.A.C.]

Recordkeeping and Reporting Requirements

C.11. Excess Emissions - Notification. In the case of excess emissions resulting from malfunctions, each owner or operator shall notify the Central District Air Section in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a semi-annual report, if requested by the Central District Air Section.
[Rule 62-210.700(6), F.A.C.]

C.12. Excess Emissions - Report. Submit to the Central District Air Section a written report of emissions in excess of emission limiting standards as set forth in this permit, for each semi-annual period. The nature and cause of the excess emissions shall be explained. This report does not relieve the owner or operator of the legal liability for violations.
[Rule 62-213.440, F.A.C.; and AC 49-205703 (PSD-FL-182)]

C.13. Test Reports.

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

1. The type, location, and designation of the emissions unit tested.
2. The facility at which the emissions unit is located.
3. The owner or operator of the emissions unit.
4. The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.
5. The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.
6. The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.
7. A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.
8. The date, starting time and duration of each sampling run.
9. The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.
10. The number of points sampled and configuration and location of the sampling plane.
11. For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.
l2. The type, manufacturer and configuration of the sampling equipment used.
13. Data related to the required calibration of the test equipment.
14. Data on the identification, processing and weights of all filters used.
15. Data on the types and amounts of any chemical solutions used.
16. Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.
17. The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.
18. All measured and calculated data required to be determined by each applicable test procedure for each run.
19. The detailed calculations for one run that relate the collected data to the calculated emission rate.
20. The applicable emission standard, and the resulting maximum allowable emission rate for the emissions unit, plus the test result in the same form and unit of measure.
21. A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

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

C.14. Frequency of Compliance Tests.

The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

(a) General Compliance Testing.

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

a. Did not operate; or

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

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

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

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

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

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

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

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

(c) Waiver of Compliance Test Requirements. If the owner or operator of an emissions unit that is subject to a compliance test requirement demonstrates to the Department, pursuant to the procedure established in Rule 62-297.620, F.A.C., that the compliance of the emissions unit with an applicable weight emission limiting standard can be adequately determined by means other than the designated test procedure, such as specifying a surrogate standard

(d) of no visible emissions for particulate matter sources equipped with a bag house or specifying a fuel analysis for sulfur dioxide emissions, the Department shall waive the compliance test requirements for such emissions units and order that the alternate means of determining compliance be used, provided, however, the provisions of Rule 62-297.310(7)(b), F.A.C., shall apply.

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

C.15. By this permit, annual emissions compliance testing for visible emissions is not required for these emissions units while burning:
a. only gaseous fuel(s); or
b. gaseous fuel(s) in combination with any amount of liquid fuel(s) for less than 400 hours per year; or
c. only liquid fuel(s) for less than 400 hours per year.
[Rule 62-297.310(7)(a)4., F.A.C.]

C.16. Appendix GG. These gas combustion turbines are each subject to 40 CFR 60 - Subpart GG, New Stationary Source Performance Standards (NSPS) for Stationary Gas Turbines (attached as Appendix GG).
[Rule 62-204. 800 (7) F.A.C and 40 CFR 60, Subpart GG, NSPS-Gas Combustion Turbines]

C.17. Appendix YYYY. This facility is subject 40 CFR 63 - Subpart YYYY, National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines (attached as Appendix YYYY) since it is a major source of hazardous air pollutants. However, all stationary combustion turbines at this facility are existing units (construction was commenced before January 14, 2003).
[Rule 62-204.800 (11) F.A.C and 40 CFR 63, Subpart A, General Provisions and Subpart YYYY, NESHAP-Combustion Turbines]

Subsection D. NSPS Common Conditions.

E.U. ID No.	Brief Description
001	Simple-Cycle Combustion Turbine Unit 1, rated at 40 MW, 367 mmBtu/hr for natural gas and 372 mmBtu/hr for number 2 fuel oil, capable of burning any combination of natural gas and number 2 fuel oil, with emissions exhausted through a 65 ft. stack. GE Model LM6000 PA
002	Combined-Cycle Combustion Turbine Unit 2, rated at 120 MW, 869 mmBtu/hr for natural gas and 928 mmBtu/hr for number 2 fuel oil, capable of burning any combination of natural gas and number 2 fuel oil, with emissions exhausted through a 75 ft. stack. GE Model PG7111EA
003 005	Combined-Cycle Combustion Turbine Unit 003 with duct burner (Unit 005), rated at 250 MW, 1696 mmBtu/hr for natural gas and 1910 mmBtu/hr for number 2 fuel oil, and capable of burning any combination of natural gas and number 2 fuel oil. Emissions are exhausted through a 100 ft. stack for simple-cycle operation, and a 130 ft. stack for combined-cycle operation. GE Model MS7241FA

The emissions units above are subject to the following conditions from 40 CFR 60 Subpart A, General Provisions. The affected units to which this subpart applies are the simple-cycle combustion turbine, Unit 001, the combined-cycle combustion turbine, Unit 002, and the combined-cycle combustion turbine, Unit 003.

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

D.1. Pursuant to 40 CFR 60.7 Notification And Record Keeping.

(a) Any owner or operator subject to the provisions of this part shall furnish the Administrator written notification as follows:
(4) A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Administrator may request additional relevant information subsequent to this notice.
(b) The owner or operator subject to the provisions of this part shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative.
(c) The owner or operator required to install a continuous monitoring system (CMS) or monitoring device shall submit an excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and/or a summary report form (see 40 CFR 60.7(d)) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the CMS data are to be used directly for compliance determination, in which case semi-annual reports shall be submitted; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each calendar half (or quarter, as appropriate). Written reports of excess emissions shall include the following information:

(1) The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.
(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.
(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.
(d) The summary report form shall contain the information and be in the format shown in Figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at each affected facility.
(1) If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in 40 CFR 60.7(c) need not be submitted unless requested by the Administrator.
(2) If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in 40 CFR 60.7(c) shall both be submitted.

[See Attached Figure 1-Summary Report-Gaseous and Opacity Excess Emission and Monitoring System Performance]

(f) The owner or operator subject to the provisions of this part shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least five years following the date of such measurements, maintenance, reports, and records.
[40 CFR 60.7 and Rule 62-213.440(1)(b)2.b., F.A.C.]

D.2. Pursuant to 40 CFR 60.8 Performance Tests.

(b) Performance tests shall be conducted and data reduced in accordance with the test methods and procedures contained in each applicable subpart.
(c) Performance tests shall be conducted under such conditions as the Administrator shall specify to the plant operator based on representative performance of the affected facility. The owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests. Operations during periods of startup, shutdown, and malfunction shall not constitute representative conditions for the purpose of a performance test nor shall emissions in excess of the level of the applicable emission limit during periods of startup, shutdown, and malfunction be considered a violation of the applicable emission limit unless otherwise specified in the applicable standard.
(f) Unless otherwise specified in the applicable subpart, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall

apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs must be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances, beyond the owner or operator's control, compliance may, upon the Administrator's approval, be determined using the arithmetic mean of the results of the two other runs.
[40 CFR 60.8]

D.3. Pursuant to 40 CFR 60.11 Compliance With Standards And Maintenance Requirements.

(a) Compliance with standards in this part, other than opacity standards, shall be determined in accordance with performance tests established by 40 CFR 60.8, unless otherwise specified in the applicable standard.
(b) Compliance with opacity standards in this part shall be determined by conducting observations in accordance with Reference Method 9 in appendix A of this part, any alternative method that is approved by the Administrator, or as provided in 40 CFR 60.11(e)(5). For purposes of determining initial compliance, the minimum total time of observations shall be 3 hours (30 6-minute averages) for the performance test or other set of observations (meaning those fugitive-type emission sources subject only to an opacity standard).
(c) The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.
(d) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
(e)(5) The owner or operator of an affected facility subject to an opacity standard may submit, for compliance purposes, continuous opacity monitoring system (COMS) data results produced during any performance test required under 40 CFR 60.8 in lieu of Method 9 observation data. If an owner or operator elects to submit COMS data for compliance with the opacity standard, he shall notify the Administrator of that decision, in writing, at least 30 days before any performance test required under 40 CFR 60.8 is conducted. Once the owner or operator of an affected facility has notified the Administrator to that effect, the COMS data results will be used to determine opacity compliance during subsequent tests required under 40 CFR 60.8 until the owner or operator notifies the Administrator, in writing, to the contrary. For the purpose of determining compliance with the opacity standard during a performance test required under 40 CFR 60.8 using COMS data, the minimum total time of COMS data collection shall be averages of all 6-minute continuous periods within the duration of the mass emission performance test. Results of the COMS opacity determinations shall be submitted along with the results of the performance test required under 60.8. The owner or operator of an affected facility using a COMS for compliance purposes is responsible for demonstrating that the COMS meets the requirements specified in 40 CFR 60.13(c), that the COMS has been properly maintained and operated, and that the resulting data have not been altered in any way. If COMS data results are submitted for compliance with the opacity standard for a period of time during which Method 9 data indicates noncompliance, the Method 9 data will be used to determine opacity compliance.
[40 CFR 60.11]

D.4. Pursuant to 40 CFR 60.12 Circumvention.

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

D.5. Pursuant to 40 CFR 60.13 Monitoring Requirements.

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B of 40 CFR 60 and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to 40 CFR 60, unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.
(c) If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data for compliance with the opacity standard as provided under 40 CFR 60.11(e)(5), he/she shall conduct a performance evaluation of the COMS as specified in Performance Specification 1, appendix B, of 40 CFR 60 before the performance test required under 40 CFR 60.8 is conducted. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under 40 CFR 60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of 40 CFR 60. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.
(1) The owner or operator of an affected facility using a COMS to determine opacity compliance during any performance test required under 40 CFR 60.8 and as described in 40 CFR 60.11(e)(5), shall furnish the Administrator two or, upon request, more copies of a written report of the results of the COMS performance evaluation described in 40 CFR 60.13(c) at least 10 days before the performance test required under 40 CFR 60.8 is conducted.
(2) Except as provided in 40 CFR 60.13(c)(1), the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.
(d)(1) Owners and operators of all continuous emission monitoring systems installed in accordance with the provisions of this part shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with a written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified. For continuous monitoring systems measuring opacity of emissions, the optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments. The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4 percent opacity.
(2) Unless otherwise approved by the Administrator, the following procedures shall be followed for continuous monitoring systems measuring opacity of emissions. Minimum procedures shall include a method for producing a simulated zero opacity condition and an upscale (span) opacity condition using a certified neutral density filter or other related technique to produce a known

obscuration of the light beam. Such procedures shall provide a system check of the analyzer internal optical surfaces and all electronic circuitry including the lamp and photo detector assembly.
(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under 40 CFR 60.13(d), all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:
(1) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring opacity of emissions shall complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.
(2) All continuous monitoring systems referenced by 40 CFR 60.13(c) for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.
(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of 40 CFR 60 shall be used.
(g) When the effluents from a single affected facility or two or more affected facilities subject to the same emission standards are combined before being released to the atmosphere, the owner or operator may install applicable continuous monitoring systems on each effluent or on the combined effluent. When the affected facilities are not subject to the same emission standards, separate continuous monitoring systems shall be installed on each effluent. When the effluent from one affected facility is released to the atmosphere through more than one point, the owner or operator shall install an applicable continuous monitoring system on each separate effluent unless the installation of fewer systems is approved by the Administrator. When more than one continuous monitoring system is used to measure the emissions from one affected facility (e.g., multiple breechings, multiple outlets), the owner or operator shall report the results as required from each continuous monitoring system.
(h) Owners or operators of all continuous monitoring systems for measurement of opacity shall reduce all data to 6-minute averages and for continuous monitoring systems other than opacity to 1-hour averages for time periods as defined in 40 CFR 60.2. Six-minute opacity averages shall be calculated from 36 or more data points equally spaced over each 6-minute period. For continuous monitoring systems other than opacity, 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorder during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph. An arithmetic or integrated average of all data may be used. The data may be recorded in reduced or non-reduced form (e.g., ppm pollutant and percent O2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in subparts. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used in the applicable subparts to specify the emission limit (e.g., rounded to the nearest 1 percent opacity).
[40 CFR 60.13]

D.6. Pursuant to 40 CFR 60.17 Incorporations by Reference.

The materials listed below are incorporated by reference in the corresponding sections noted. [Note: The remainder of this section has not been reproduced in this permit for brevity. See 40 CFR 60.17 for materials incorporated by reference.]
[40 CFR 60.17]

Subsection E. This section addresses the following emissions units.

E.U. ID Nos.	Brief Description
003 and 005	These units are comprised of a combined-cycle combustion turbine plant that includes (a) a stationary gas turbine (Unit 003), (b) a supplementary gas-fired heat recovery steam generator (HRSG) with duct burner (Unit 005), and (c) a steam turbine. The plant is rated at 250 MW, 1696 mmBtu/hr for natural gas and 1910 mmBtu/hr for number 2 fuel oil, and capable of burning any combination of natural gas and number 2 fuel oil. Emissions are exhausted through a 100 ft. stack for simple-cycle operation, and a 130 ft. stack for combined-cycle operation. Emission Unit 003 is a General Electric Model MS7241FA

This combustion turbine is regulated under Phase II of the federal Acid Rain Program; Rule 62-210.300, F.A.C., Permits Required; and, is subject to 40 CFR 60, Subpart GG, Standards of Performance for New Stationary Gas Turbines (attached as Appendix GG). The HRSG equipped with a natural gas fired 44 mmBTU/hr duct burner (HHV) and 80-90 MW steam electrical generator shall comply with all applicable provisions of 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial Commercial-Institutional Steam Generating Units Which Construction is Commenced After September June 9, 1989, adopted by reference in Rule 62-204.800(7), F.A.C. Since this unit is located at a major source for hazardous air pollutants, this unit is also subject to 40 CFR 63, Subpart YYYY, National Emissions Standards for Hazardous Air Pollutants for Combustion Turbines (attached as Appendix YYYY). See Specific Conditions **C.16** and **C.17**.

Simple-cycle control technology includes (a) dry low nitrogen oxides (NOx) (DLN) combustors to control NOx emissions during periods of natural gas use, and (b) a water injection system to control NOx emissions during periods of distillate fuel oil use.

Combined-cycle control technology includes (a) a selective catalytic reduction system (SCR) to control NOx emissions, (b) DLN combustors to control NOx emissions during periods of natural gas use, and (c) a water injection system to control NOx emissions during periods of distillate fuel oil use. Because a continuous emissions monitoring system (CEMS) is used to demonstrate compliance for NO_X, a compliance assurance monitoring (CAM) plan is not required for the SCR system.

This turbine was permitted on November 22, 1999 and began commercial operation in 2001.

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

Essential Potential to Emit (PTE) Parameters

E.1. Combustion Turbine Capacity. The maximum heat input rates, based on the lower heating value (LHV) of each fuel to this Unit at ambient conditions of 19°F temperature, 55% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,696 million Btu per hour (mmBtu/hr) when firing natural gas, and not exceed 1,910 mmBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions were required to be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing by the permittee.
[Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); and PSD-FL-254, Specific Condition 10.]

E.2. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate of the natural gas fired duct burner shall not exceed 44 mmBtu/hour (HHV).

[Rule 62-210.200 F.A.C. (Definitions - Potential Emissions), Rule 62-4.160(2) F.A.C., and PSD-FL-254, Specific Condition 11.]

E.3. Emissions Unit Operating Rate Limitation After Testing. See Specific Condition **C.8.**
[Rule 62-297.310(2), F.A.C.]

Methods of Operation

E.4. Operating Procedures. Operating procedures shall include good operating practices and proper training of all operators and supervisors. The good operating practices shall meet the guidelines and procedures as established by the equipment manufacturers. All operators (including supervisors) of air pollution control devices shall be properly trained in plant specific equipment.
[Rule 62-4.070(3), F.A.C.; and PSD-FL-254, Specific Condition 14.]

E.5. Circumvention. The owner or operator shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly.
[Rule 62-210.650, F.A.C.; and PSD-FL-254, Specific Condition 15.]

E.5.1. Maximum allowable hours of operation for the 250 MW Combined-Cycle Unit are 8760 hours per year while firing natural gas. Fuel oil firing of the combustion turbine is permitted for a maximum of 720 hours per year.
[Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); PSD-FL-254, Specific condition 16.]

E.5.2. Simple-Cycle Operation. The plant may be operated in simple-cycle mode. Different limits apply depending upon whether simple-cycle operation is of an intermittent nature (e.g., caused by maintenance of equipment following the combustion turbine, or temporary electrical demand fluctuations), or long-term electrical demand situations.
[PSD-FL-254, Specific Condition 17.]

E.6. Fuels. Only pipeline natural gas or a maximum of 0.05 percent, by weight, sulfur fuel oil (No. 2 or superior grade of distillate fuel oil) shall be fired in this unit.
[Rule 62-210.200, F.A.C. (Definitions - Potential Emissions); and PSD-FL-254, Specific Condition 9.]

Control Technology

E.7. Dry Low NO_X (DLN) combustors are installed on the stationary combustion turbine to comply with the simple-cycle NO_X emissions limits listed in Specific Condition **E.13.**
[Rules 62-4.070 and 62-212.400, F.A.C.; and PSD-FL-254, Specific Condition 18.]

E.8. A water injection system is installed for use when firing No. 2 or superior grade distillate fuel oil for control of NO_X emissions.
[Rules 62-4.070 and 62-212.400, F.A.C.; and PSD-FL-254, Specific Condition 19.]

E.9. A selective catalytic reduction (SCR) system is installed to comply with the combined-cycle NO_X limit listed in Specific Condition **E.13.**
[PSD-FL-254, Specific Condition 20.]

E.10. These units are designed to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions **E.13.** through **E.17.**
[Rules 62-4.070 and 62-204.800, F.A.C.; 40 CFR60.40a(b); and PSD-FL-254, Specific Condition 21.]

E.11. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize simple-cycle NO_X emissions and CO emissions.
[Rules 62-4.070 and 62-210.650 F.A.C.; and PSD-FL-254, Specific Condition 22.]

E.12. Drift eliminators are installed on the cooling tower to reduce PM/PM_{10} emissions.
[PSD-FL-254, Specific Condition 23.]

Emission Limitations and Standards

{Permitting note: Unless otherwise specified, the averaging times for Specific Conditions **E.13.** through **E.17.** are based on the specified averaging time of the applicable test method.}

E.13. Nitrogen Oxides.

A. Combined-Cycle Operation

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas (fuel oil) and the duct burner on or off, shall not exceed 3.5 (15) ppmvd @15% O_2 on a 3-hr block average. Compliance shall be determined by the continuous emission monitor (CEMS). Emissions of NO_X calculated as NO_2 in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 26 (108) pounds per hour (lb/hr) with the duct burner on or off to be demonstrated by *initial* stack test.

- The concentration of ammonia in the exhaust gas from each combustion turbine shall not exceed 5 ppmvd @15% O_2. The compliance procedures are described in Specific Condition **E.21.** [Rules 62-212.400 and 62-4.070, F.A.C.]

- When NO_X monitoring data are not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

B. Intermittent Simple-Cycle Operation

The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas (fuel oil) shall not exceed 12 (42) ppmvd at 15% O_2 (24-hr block average). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 86 (310) pounds per hour (lb/hr). [Rule 62-212.400, F.A.C.]

- Notwithstanding the applicable NO_X limit during simple-cycle operation, reasonable measures shall be implemented to maintain the concentration of NO_X in the exhaust gas at 9 ppmvd at 15% O_2 or lower. Any tuning of the combustors for Dry Low NO_X operation while firing gas shall result in initial subsequent NO_X concentrations of 9 ppmvd @15% O_2 or lower.
[Rules 62-212.400 and 62-4.070, F.A.C.]

- When NO_X monitoring data are not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

C. Continuous Simple-Cycle Operation

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas (fuel oil) shall not exceed 9 (42) ppmvd at 15% O_2 (24-hr block average). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 65 (310) pounds per hour (lb/hr). [Rules 62-212.400, F.A.C.]
- Notwithstanding the applicable NO_X limit during simple-cycle operation, reasonable measures shall be implemented to maintain the concentration of NO_X in the exhaust gas at 9 ppmvd at 15% O_2 or lower. Any tuning of the combustors for Dry Low NO_X operation while firing gas shall result in initial subsequent NO_X concentrations of 9 ppmvd @15% O_2 or lower. [Rules 62-212.400 and 62-4.070, F.A.C.]
- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

[PSD-FL-254, Specific Condition 24.]

E.14. Carbon Monoxide. Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas (fuel oil) shall neither exceed 12 (20) ppm, nor exceed 43 (71) lb/hr, with the duct burner off, and neither exceed 20 (30) ppm, nor exceed 71 (108) lb/hr, with the duct burner on, to be demonstrated by stack test using EPA Method 10.
[Rule 62-212.400, F.A.C.; and PSD-FL-254, Specific Condition 25.]

E.15. Volatile Organic Compounds. Emissions of VOC in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas (fuel oil) shall neither exceed 1.4 (10) ppm, nor exceed 3 (21.4) lb/hr, with the duct burner off, and neither exceed 4 (10) ppm, nor exceed 8.5 (21.4) lb/hr, with the duct burner on, to be demonstrated by *initial* stack test using EPA Method 18, 25 or 25A. No annual testing is required.
[Rule 62-212.400, F.A.C.; and PSD-FL-254, Specific Condition 26.]

E.16. Sulfur Dioxide. SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 20 grains per 100 standard cubic foot), or by firing No. 2 or superior grade distillate fuel oil with a maximum 0.05 percent sulfur, by weight, for 720 hours per year. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions **E.32.** and **E.33.** will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner or the combustion turbine. Emissions of SO_2 shall not exceed 38.1 tons per year.
[40 CFR 60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C. to avoid PSD Review; and PSD-FL-254, Specific Condition 27.]

E.17. Visible Emissions. VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine operating with or without the duct burner, and shall not exceed 10 percent opacity from the stack in use.
[Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.; and PSD-FL-254, Specific Condition 28.]

Excess Emissions

E.18. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall

be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period. During any calendar day in which a start-up or shutdown occurs with natural gas as the exclusively fired fuel, an alternative NO_X limit of 86 lb/hr (310 lb/hr if fuel oil is fired during the calendar day) on the basis of a 24-hour average shall apply.
[Rule 62-210.700, F.A.C.; and PSD-FL-254, Specific Condition 29., as modified on November 26, 2002.]

E.19. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_X.
[PSD-FL-254, Specific Condition 30.]

E.20. Excess Emissions Report. If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Central District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition **E.13.**
[Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7 (1998 version); and PSD-FL-254, Specific Condition 31.]

Compliance Determination

E.21. Selective Catalytic Reduction System (SCR) Compliance Procedures.

- An *initial* stack emission test for nitrogen oxides and ammonia from the CGT/HRGS pair was conducted: 1) for natural gas firing, and 2) for distillate fuel oil firing. The ammonia injection rate necessary to comply with the NO_X standard was established during the initial performance tests.
- The SCR equipment shall operate at all times that the combustion turbine is operating in combined-cycle operation mode. The permittee shall, whenever possible, operate the facility in a manner so as to optimize the effectiveness of the SCR unit, while minimizing ammonia slip to below the emission limit.
- The permittee shall operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system of the CGT/HRSG set. It shall be maintained and calibrated according to the manufacture's specifications. During the stack test, the permittee at each load condition shall determine the minimum ammonia flow rate required to meet the emissions limitations. During NO_X CEM downtimes or malfunctions, the permittee shall operate at greater or equal to 100% of the ammonia injection rate determined during the stack test.

[PSD-FL-254, Specific Condition 52.]

E.22. Compliance with the allowable emission limiting standards shall be determined annually as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.
[PSD-FL-254, Specific Condition 32.]

E.23. Annual compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources".
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources".
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Tests must be conducted with the duct burner on and with the duct burner off.
- EPA Method 26A (modified) for ammonia sample collection.
- EPA Draft Method 206 for ion chromatographic analysis for ammonia.

[PSD-FL-254, Specific Condition 33.]

E.24. Continuous compliance with the NO_X emission limits. Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system on a 3-hr average basis (a 24-hour block average shall be used to demonstrate compliance with the NO_x limits when operating under Intermittent Simple-Cycle Operation or Continuous Simple-Cycle Operation). Based on CEMS data, a separate compliance determination is conducted at the end of each 3-hr period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous 3-hr period. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700, F.A.C. 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. These excess emissions periods shall be reported as required in Specific Condition **E.20.**
[Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75; and PSD-FL-254, Specific Condition 34.]

E.25. Compliance with the SO_2 and PM/PM_{10} emission limits. Notwithstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR 60.335 or 40 CFR 75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1998 version).
[PSD-FL-254, Specific Condition 35.]

E.26. Compliance with CO emission limit. An *initial* test for CO, was conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of

three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75. As an alternative to annual testing in a given year, periodic tuning data shall be provided to demonstrate compliance in the year the tuning is conducted.
[PSD-FL-254, Specific Condition 36.]

E.26.1 Compliance with the VOC emission limit. An *initial* test was required to demonstrate compliance with the VOC emission limit. Subsequently, the CO emission limit and periodic tuning data shall be employed as surrogate and no annual testing is required.
[PSD-FL-254, Specific Condition 37.]

E.27. Testing procedures. Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.
[PSD-FL-254, Specific Condition 38.]

Monitoring of Operations

E.28. Continuous Monitoring System. The permittee shall calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the NO_X from these units. Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the permitted limits, listed in Specific Condition **E.13.** (other than those allowed for in Specific Condition **E.18.**) shall be reported to the DEP Central District Office within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternatively by facsimile within one working day).
[Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C.; 40 CFR 60.7 (1998 version); and PSD-FL-254, Specific Condition 44., as modified on November 26, 2002.]

E.29. CEMS for reporting excess emissions. The NO_X CEMS shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). Upon request from DEP, the CEMS emission rates for NO_X on the CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.
[EPA approval letter dated February 10, 1999; and PSD-FL-254, Specific Condition 45.]

E.30. CEMS in lieu of Water to Fuel Ratio. The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). Subject to EPA approval, the calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1998 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emission rates for NO_X on this Unit shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332.
[EPA Approval dated February 10, 1999; and PSD-FL-254, Specific Condition 46.]

E.31. Continuous Monitoring System Reports. The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40 CFR 75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.
[PSD-FL-254, Specific Condition 47.]

E.32. Natural Gas Monitoring Schedule. A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
- Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75, and certified by the USEPA.

This custom fuel monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

[PSD-FL-254, Specific Condition 48.]

E.33. Fuel Oil Monitoring Schedule. The following monitoring schedule for No. 2 or superior grade fuel oil shall be followed: For all bulk shipments of No. 2 fuel oil received at this facility an analysis which reports the sulfur content and nitrogen content of the fuel shall be provided by the fuel vendor. The analysis shall also specify the methods by which the analyses were conducted and shall comply with the requirements of 40 CFR 60.335(d).
[PSD-FL-254, Specific Condition 49.]

Recordkeeping and Reporting Requirements

E.34. Semi-Annual Reports. Semi-annual excess emission reports, in accordance with 40 CFR 60.7(a)(7)(c), shall be submitted to the DEP's Central District Office.
[PSD-FL-254, Specific Condition 14, in Section II.]

E.35. Test Notification. The DEP's Central District office shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s).
[PSD-FL-254, Specific Condition 39.]

E.36. Special Compliance Tests. The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.
[PSD-FL-254, Specific Condition 40.]

E.37. Test Results. Compliance test results shall be submitted to the DEP's Central District office no later than 45 days after completion of the last test run.
[Rule 62-297.310(8), F.A.C.; and PSD-FL-254, Specific Condition 41.]

E.38. Records. All measurements, records, and other data required to be maintained by KUA shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request.
[PSD-FL-254, Specific Condition 42.]

E.39. Compliance Test Reports. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.
[PSD-FL-254, Specific Condition 43.]

E.40. Subpart Dc Requirements. The permittee shall comply with all applicable requirements of 40 CFR 60, Subpart Dc.
[PSD-FL-254, Specific Condition 51.]

Other Specific Conditions

E.41. This emissions unit is also subject to conditions **C.1.** through **C.17.,** contained in **Subsection C., Common Conditions.**

E.42. This emissions unit is also subject to conditions **D.1.** through **D.6.,** contained in **Subsection D., NSPS Common Conditions.**

Subsection F. This section addresses the following emissions unit.

E.U. ID No.	Brief Description
004	Fuel Storage Tank

This fuel storage unit, consisting of a 1.0 million gallon distillate fuel oil storage tank (Unit 004), shall comply with all applicable provisions of 40 CFR 60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C. [PSD-FL-254, Specific Condition 5.]

The following conditions apply to the emissions unit listed above:

Essential Potential to Emit (PTE) Parameters

F.1. Hours of Operation. This emissions unit is allowed to operate continuously, i.e., 8,760 hours/year.
[Rules 62-4.160(2) and 62-210.200, F.A.C., Definitions - (PTE).]

Recordkeeping Requirements

F.2. The permittee shall maintain records on site for storage vessel identification number 004 to include the date of construction, the material storage capacity, and type of material stored for the life of this storage vessel.
[40 CFR 60.116b(b).]

Section IV. This section is the Acid Rain Part.

Operated by: Kissimmee Utility Authority
ORIS code: **7238**

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

The emissions units listed below are regulated under Phase II of the federal Acid Rain Program.

E.U. ID No.	Brief Description
001	Simple-Cycle Combustion Turbine (Unit 001)
002	Combined-Cycle Combustion Turbine (Unit 002)
003	Combined-Cycle Combustion Turbine (Unit 003)

A.1. The Phase II Part Application submitted for this facility, as approved by the Department, is a part of this permit. The owners and operators of these Phase II acid rain unit(s) must comply with the standard requirements and special provisions set forth in the application listed below:
a. DEP Form No. 62-210.900(1)(a). signed by the Designated Representative on June 25, 2004.
[Chapter 62-213, F.A.C., and Rule 62-214.320, F.A.C.]

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

E.U. ID No.	EPA ID	Year	2005	2006	2007	2008	2009
001	**1**	SO_2 allowances to be determined by USEPA	0*	0*	0*	0*	0*
002	**2**	SO_2 allowances to be determined by USEPA	0*	0*	0*	0*	0*
003	**3**	SO_2 allowances to be determined by USEPA	0*	0*	0*	0*	0*

* The number of allowances held by an Acid Rain source in a unit account may differ from the number allocated by USEPA.

A.3. Fast-Track Revisions of Acid Rain Parts. Those Acid Rain sources making a change described at Rule 62- 214.370(4), F.A.C., may request such change as provided in Rule 62-213.413, F.A.C., Fast-Track Revisions of Acid Rain Parts.
[Rules 62-213.413 and 62-214.370(4), F.A.C.]

A.4. Comments, notes, and justifications. None.

Appendix I-1, List of Insignificant Emissions Units and/or Activities

The facilities, emissions units, or pollutant-emitting activities listed in Rule 62-210.300(3)(a), F.A.C., Categorical Exemptions, or that meet the criteria specified in Rule 62-210.300(3)(b)1., F.A.C., Generic Emissions Unit Exemption, are exempt from the permitting requirements of Chapters 62-210, 62-212 and 62-4, F.A.C.; provided, however, that exempt emissions units shall be subject to any applicable emission limiting standards and the emissions from exempt emissions units or activities shall be considered in determining the potential emissions of the facility containing such emissions units. Emissions units and pollutant-emitting activities exempt from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., shall not be exempt from the permitting requirements of Chapter 62-213, F.A.C., 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 also meet the criteria of Rule 62-213.430(6)(b), F.A.C. No emissions unit shall be entitled to an exemption from permitting under Rules 62-210.300(3)(a) and (b)1., F.A.C., if its emissions, in combination with the emissions of other units and activities at the facility, would cause the facility to emit or have the potential to emit any pollutant in such amount as to make the facility a Title V source.

The below listed emissions units and/or activities are considered insignificant pursuant to Rule 62-213.430(6), F.A.C.

Brief Description of Emissions Units and/or Activities
Natural Gas Fuel Gas Heater.

Appendix H-1, Permit History/ID Number Changes

Permit History (for tracking purposes):

E.U. ID No.	Description	Permit No.	Issue Date	Expiration Date	Extended Date[1, 2]
Unit 1	Simple-Cycle Comb. Turbine, Unit 1	AC49-205703 PSD-FL-182	4/9/93	11/1/96	9/16/94, 5/8/95
	To burn very low sulfur oil up to 800 hrs	0970043-004-AC	5/19/97		
	To allow NOx CEM compliance	970043-003-AC	8/15/97		
	Extension of time to lower NOx limit from 25 to 15 ppmvd	0970043-005-AC	12/17/98		
	Set NOx limit for Unit 1 at 25 ppmvd, reduce Unit 1 to 5000 hr/yr, establish NOx cap for Units 1 and 2	0970043-007-AC	12/21/99		
Unit 2	Combined-Cycle Gas Turbine, Unit 2	AC49-205703 PSD-FL-182	4/9/93	11/1/96	9/16/94, 5/8/95
	To burn very low sulfur oil up to 800 hrs	0970043-004-AC	5/19/97		
	To allow NOx CEM compliance	0970043-003-AC	8/15/97		
	Set NOx limit for Unit 1 at 25 ppmvd, reduce Unit 1 to 5000 hr/yr, establish NOx cap for Units 1 and 2	0970043-007-AC	12/21/99		
	Added inlet air fogging for Unit 2	0970043-008-AC (PSD-FL-182I)	10/13/00		
	Added inlet air fogging for Unit 2 in initial Title V permit	0970043-009-AV	10/13/00	12/31/04	
Unit 3	Combined-Cycle Gas Turbine, Unit 3 To modify excess emission condition	PSD-FL-254 PA 98-38 0970043-011-AC 0970043-012-AV	 11/22/99 11/27/02 Withdrawn	12/31/02	
All Title V	Unit 1, Unit 2 and Unit 3 Initial Title V Revision to add Unit 2 foggers Revision to add Unit 3 Withdrawn request Renewal	 0970043-002-AV 0970043-009-AV 0970043-010-AV 0970043-012-AV 0970043-013-AV	 06/01/99 10/13/00 11/17/03 Withdrawn 01/01/2005	 12/31/04 12/31/04 12/31/04 12/31/09	

ID Number Changes (for tracking purposes):
From: **Facility ID No.:** 30ORL490043
To: **Facility ID No.:** 0970043

Notes:
1 - AO permit(s) automatic extension(s) in Rule 62-210.300(2)(a)3.a., F.A.C., effective 03/21/96.
2 - AC permit(s) automatic extension(s) in Rule 62-213.420(1)(a)4., F.A.C., effective 03/20/96.
{Rule 62-213.420(1)(b)2., F.A.C., effective 03/20/96, allows Title V Sources to operate under existing valid permits}

Appendix U-1, List of Unregulated Emissions Units and/or Activities

Unregulated Emissions Units and/or Activities. An emissions unit which emits no "emissions-limited pollutant" and which is subject to no unit-specific work practice standard, though it may be subject to regulations applied on a facility-wide basis (e.g., unconfined emissions, odor, general opacity) or to regulations that require only that it be able to prove exemption from unit-specific emissions or work practice standards.

The below listed emissions units and/or activities are neither 'regulated emissions units' nor 'exempt emissions units'.

E.U. ID No.	Brief Description of Emissions Units and/or Activity
007	Distillate Fuel Oil Tank No. 2 (700,000 gal. capacity)
008	Distillate Fuel Oil Tank No. 1 (300,000 gal. capacity)
006	Cooling Tower

Table 1-1, Summary of Air Pollutant Emission Standards

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

E.U. ID	Brief Description
001	Simple-Cycle Gas Turbine, Unit 1, rated at 40 MW.

			Allowable Emissions[a]			Equivalent			
Pollutant	Fuel(s)	Hours	Standard(s)	lb/hr	TPY	lb/hr	TPY	Regulatory	See Permit
VE	No 2 Oil Nat Gas	5000	10 % opacity					AC 49-205703	A.4.
SO_2	No 2 Oil Nat Gas	1000	0.05% S by weight, fuel oil	20			10	AC 49-205703	A.9., A.10., A.13.
NO_x**	No. 2 Fuel Oil	1000	42 ppmvd at 15% oxygen on a dry	63			31.5	AC 49-205703	A.5., C.1
NO_x**	Natural Gas	5000	25 ppmvd at 15% oxygen dry basis	37			74.0	AC 49-205703	A.5., C.1
PM	No. 2 Fuel Oil	1000	0.0323 lb/MMBtu			12.0	6.0	AC 49-205703	A.5., A.7.
PM	Natural Gas	5000	0.0245 lb/MMBtu			9	18.0	AC 49-205703	A.5., A.7.
VOC	No. 2 Fuel Oil	1000	3 lb/hour	3			1.5	AC 49-205703	A.5., A.7.
VOC	Natural Gas	5000	1.4 lb/hour	1.4			2.8	AC 49-205703	A.5., A.7.
CO	No. 2 Fuel Oil	1000	63 ppmvd at 15% oxygen on a dry	76			38	AC 49-205703	A.5., A.7.
CO	Natural Gas	5000	30 ppmvd at 15% oxygen on a dry	40			80.0	AC 49-205703	A.5., A.7.
Hg	No. 2 Fuel Oil	1000	3.1 E-6 lb/mmBtu			<1	<1	AC 49-205703	A.5.
As	No. 2 Fuel Oil	1000	4.2 E-6 lb/mmBtu			<1	<1	AC 49-205703	A.5.
Be	No. 2 Fuel Oil	1000	2.5 E-6 lb/mmBtu			<1	<1	AC 49-205703	A.5.
Pb	No. 2 Fuel Oil	1000	2.8 E-5 lb/mmBtu			<1	<1	AC 49-205703	A.5.

Notes for EU 001:

a No. 2 fuel oil firing is limited to 1000 hours per year. Total operation is limited to 5000 hours per year.

[1] The "Equivalent Emissions" listed are for informational purposes only. They are based upon 4000 hours per year of gas operation and 1000 hours per year of #2 oil operation. [Rule 62-213.205, F.A.C.]

* Firing of number 2 fuel oil is limited to no more than 1000 hours per year to the unit for any reason.

** {Permitting Note: Emissions Units 001 and 002 have a combined NOx emissions cap of 366.1 during any consecutive 12 months. Last revised by Project No. 0970043-009-AV on 10/13/00.}

E.U. ID	Brief Description
002	Combined-Cycle Gas Turbine, Unit 2, rated at 120 MW.

			Allowable Emissions[a]			Equivalent			
Pollutant	Fuel(s)	Hours	Standard(s)	lb/hr	TPY	lb/hr	TPY	Regulatory	See Permit
VE	No 2 Oil Nat Gas	8760	10 % opacity					AC 49-205703	A.4.
SO_2	No 2 Oil Nat Gas	1000	0.05% S by weight, fuel oil	52			26	AC 49-205703	A.9., A.10., A.13.
NO_x	No. 2 Fuel Oil	1000	42 ppmvd at 15% oxygen on a dry	170			85.0	AC 49-205703	A.15.
NO_x	Natural Gas	8760	15 ppmvd at 15% oxygen on a dry	53			205.6	AC 49-205703	A.15.
PM	No. 2 Fuel Oil	1000	0.0162 lb/MMBtu			15.0	7.5	AC 49-205703	A.5., A.7.
PM	Natural Gas	8760	0.0100 lb/MMBtu			8.7	33.7	AC 49-205703	A.5., A.7.
VOC	No. 2 Fuel Oil	1000	5.0 lb/hour	5			2.5	AC 49-205703	A.5., A.7.
VOC	Natural Gas	8760	2.0 lb/hour	2			7.76	AC 49-205703	A.5., A.7.
CO	No. 2 Fuel Oil	1000	20 ppmvd at 15% oxygen on a dry	65			32.5	AC 49-205703	A.5., A.7.
CO	Natural Gas	8760	20 ppmvd at 15% oxygen on a dry	54			209.5	AC 49-205703	A.5., A.7.
Hg	No. 2 Fuel Oil	1000	3.0e-6 lb/mmBtu			<1	<1	AC 49-205703	A.5.
As	No. 2 Fuel Oil	1000	4.2e-6 lb/mmBtu			<1	<1	AC 49-205703	A.5.
Be	No. 2 Fuel Oil	1000	2.5e-6 lb/mmBtu			<1	<1	AC 49-205703	A.5.
Pb	No. 2 Fuel Oil	1000	2.8e-5 lb/mmBtu			<1	<1	AC 49-205703	A.5.

Notes for EU 002:

a lb/hour and TPY values based on using number 2 fuel oil for 1000 hours per year; for natural gas using 7760 hours per year.

[1] The "Equivalent Emissions" listed are for informational purposes only. They are based upon 7760 hours per year of gas operation and 1000 hours per year of #2 oil operation. [Rule 62-213.205, F.A.C.]

* Firing of number 2 fuel oil is limited to no more than 1000 hours per year to the unit for any reason.

{Permitting Note: Emissions Units 001 and 002 have a combined NOx emissions cap of 366.1 during any consecutive 12 months. Last revised by Project No. 0970043-009-AV on 10/13/00.}

E.U. ID	Brief Description
003	Combined-Cycle Gas Turbine, Unit 3, with HRSG and duct burner, rated at 250 MW.

			Allowable Emissions			Equivalent			
Pollutant	Fuel(s)	Hours	Standard(s)	lb/hr	TPY	lb/hr	TPY	Regulatory	See Permit
VE	No 2 Oil or Nat Gas		< 10 percent opacity					PSD-FL-254	**E.17.**
SO_2	No. 2 Fuel Oil	720	Maximum .0005 sulfur by weight		38.1				**E.16.**
	Natural Gas	8760	20 grains per 100 scf						
NO_x	No. 2 Fuel Oil	720	15 ppmvd	108					**E.13.**
	Natural Gas		3.5 ppmvd	26					
VOC	No. 2 Fuel Oil	720							
	(duct burner off)		10 ppm	21.4					**E.15.**
	(duct burner on)		10 ppm	21.4					**E.15.**
VOC	Natural Gas								
	(duct burner off)		1.4 ppm	3					**E.15.**
	(duct burner on)		4 ppm	8.5					**E.15.**
CO	No. 2 Fuel Oil	720							
	(duct burner off)		20 ppm	71					**E.14.**
	(duct burner on)		30 ppm	108					**E.14.**
CO	Natural Gas								
	(duct burner off)		12 ppm	43					**E.14.**
	(duct burner on)		20 ppm	71					**E.14.**

Table 2-1, Summary of Compliance Requirements

This table summarizes information for convenience purposes only. This table does not supersede any of the terms or conditions of this permit.

Emissions Unit	Brief Description
001	Simple-Cycle Combustion Turbine, Unit 1, rated at 40 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Test Duration	CMS[2]	See Permit Condition(s)
VE	No 2 Fuel Oil, Nat. Gas	EPA Method 9	Annual	August 1st	1 hour	No	A.6.
SO_2	"	Method 8 for Fuel oil firing only; Fuel Sampling & Analysis	As Fired			Yes*	A.9, A.10.
NO_x	"	EPA Test Method 20	Annual	August 1st	3 hours	Yes	A.6.
PM	"	EPA Test Methods 5 or 17	Only if 10% Opacity is exceeded		3 hours	No	A.7.
VOC	"	EPA Test Method 25A	Initial Compliance			No	A.7.
CO	"	EPA Test Method 10	Annual			No	A.7.
Hg	No.2 oil	EPA Method 101 or fuel sampling	Initial Compliance			No	A.5.
As	No.2 oil	Fuel sampling	Initial Compliance			No	A.5.
Be	No.2 oil	EPA Method 104 or fuel sampling	Initial Compliance			No	A.5.
Pb	No.2 oil	Fuel sampling	Initial Compliance			No	A.5.

Notes for EU 001:

* Continuous monitoring of fuel consumption required.
[1] Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.
[2] CMS = continuous monitoring system
See also Section C for general testing requirements

{Permitting Note: Emissions Units 001 and 002 have a combined NOx emissions cap of 366.1 during any consecutive 12 months. Compliance must be demonstrated monthly by CEMS data. Last revised by Project No. 0970043-009-AV on 10/13/00.}

Emissions Unit	Brief Description
002	Combined-Cycle Combustion Turbine, Unit 2, rated at 120 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Test Duration	CMS[2]	See Permit Condition(s)
VE	No 2 Fuel Oil, Nat. Gas	EPA Method 9	Annual	August 1st	1 hour	No	B.6.
SO_2	"	Method 8 for Fuel oil firing only; Fuel Sampling & Analysis	As Fired			Yes*	B.9, B.10.
NO_x	"	EPA Test Method 20	Annual	August 1st	3 hours	Yes	B.6.
PM	"	EPA Test Methods 5 or 17	Only if 10% Opacity is exceeded		3 hours	No	B.7.
VOC	"	EPA Test Method 25A	Initial Compliance			No	B.7.
CO	"	EPA Test Method 10	Annual			No	B.7.
Hg	No.2 oil	EPA Method 101 or fuel sampling	Initial Compliance			No	B.5.
As	No.2 oil	Fuel sampling	Initial Compliance			No	B.5.
Be	No.2 oil	EPA Method 104 or fuel sampling	Initial Compliance			No	B.5.
Pb	No.2 oil	Fuel sampling	Initial Compliance			No	B.5.

Notes for EU 002:

***** Continuous monitoring of fuel consumption required.
[1] Frequency base date established for planning purposes only; see Rule 62-297.310, F.A.C.
[2] CMS = continuous monitoring system
See also Section F for general testing requirements.

{Permitting Note: Emissions Units 001 and 002 have a combined NOx emissions cap of 366.1 during any consecutive 12 months. Compliance must be demonstrated monthly by CEMS data. Last revised by Project No. 0970043-009-AV on 10/13/00.}

Emissions Unit	Brief Description
003	Combined-Cycle Combustion Turbine, Unit 3, rated at 250 MW.

Pollutant or Parameter	Fuel(s)	Compliance Method	Testing Frequency	Frequency Base Date[1]	Minimum Compliance Test Duration	CMS	See Permit Condition(s)
VE	No 2 Fuel Oil, Nat. Gas	EPA Method 9	Annual	August 1st	1 hour		**E.23.**
SO_2	"	Fuel Sampling & Analysis	Daily				**E.16., E.25, E.32., E.33.**
NO_x	"	EPA Test Method 20	Annual	August 1st	3 hours	Yes	**E.23.**
CO	"	EPA Test Method 10	Annual				**E.23.**

APPENDIX YYYY

NESHAP REQUIREMENTS FOR GAS TURBINES

The Kissimmee Utilities Authority Cane Island Facility is an existing major source of hazardous air pollutant emissions. As such, it is an "affected source" with respect to 40 CFR 63, Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Permits promulgated on March 5, 2004.

According to the applicable rule at 40 CFR 63.6090(b)(4), "Existing combustion turbines in all subcategories do not have to meet the requirements of this subpart and of Subpart A of this part. No initial notification is necessary for any existing stationary combustion turbine, even if a new or reconstructed turbine in the same category would require an initial notification".

Thus Subpart YYYY imposes no additional requirements on this facility unless the units are reconstructed or new units are added.

APPENDIX GG
NSPS for Gas Combustion Turbines

Updated 7/8/04

Source [44 FR 52798, Sept. 10, 1979, as amended at 52 FR 42434, Nov. 5, 1987; 65 FR 61759, Oct. 17, 2000; 69 FR 41346, July 8, 2004]

Subpart GG-Standards of Performance for Stationary Gas Turbines

§ 60.330 Applicability and designation of affected facility.

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of § 60.332.

§ 60.331 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in subpart A of this part.

(a) *Stationary gas turbine* means any simple cycle gas turbine, regenerative cycle gas turbine or any gas turbine portion of a combined cycle steam/electric generating system that is not self propelled. It may, however, be mounted on a vehicle for portability.

(b) *Simple cycle gas turbine* means any stationary gas turbine which does not recover heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine, or which does not recover heat from the gas turbine exhaust gases to heat water or generate steam.

(c) *Regenerative cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to preheat the inlet combustion air to the gas turbine.

(d) *Combined cycle gas turbine* means any stationary gas turbine which recovers heat from the gas turbine exhaust gases to heat water or generate steam.

(e) *Emergency gas turbine* means any stationary gas turbine which operates as a mechanical or electrical power source only when the primary power source for a facility has been rendered inoperable by an emergency situation.

(f) *Ice fog* means an atmospheric suspension of highly reflective ice crystals.

(g) *ISO standard day conditions* means 288 degrees Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

(h) *Efficiency* means the gas turbine manufacturer's rated heat rate at peak load in terms of heat input per unit of power output based on the lower heating value of the fuel.

(i) *Peak load* means 100 percent of the manufacturer's design capacity of the gas turbine at ISO standard day conditions.

(j) *Base load* means the load level at which a gas turbine is normally operated.

(k) *Fire-fighting turbine* means any stationary gas turbine that is used solely to pump water for extinguishing fires.

(l) *Turbines employed in oil/gas production or oil/gas transportation* means any stationary gas turbine used to provide power to extract crude oil/natural gas from the earth or to move crude oil/natural gas, or products refined from these substances through pipelines.

(m) A *Metropolitan Statistical Area* or *MSA* as defined by the Department of Commerce.

(n) *Offshore platform gas turbines* means any stationary gas turbine located on a platform in an ocean.

(o) *Garrison facility* means any permanent military installation.

(p) *Gas turbine model* means a group of gas turbines having the same nominal air flow, combuster inlet pressure, combuster inlet temperature, firing temperature, turbine inlet temperature and turbine inlet pressure.

(q) *Electric utility stationary gas turbine* means any stationary gas turbine constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale.

(r) *Emergency fuel* is a fuel fired by a gas turbine only during circumstances, such as natural gas supply curtailment or breakdown of delivery system, that make it impossible to fire natural gas in the gas turbine.

(s) Unit operating hour means a clock hour during which any fuel is combusted in the affected unit. If the unit combusts fuel for the entire clock hour, it is considered to be a full unit operating hour. If the unit combusts fuel for only part of the clock hour, it is considered to be a partial unit operating hour.

(t) Excess emissions means a specified averaging period over which either:

(1) The NO_X emissions are higher than the applicable emission limit in Sec. 60.332;

(2) The total sulfur content of the fuel being combusted in the affected facility exceeds the limit specified in Sec. 60.333; or

(3) The recorded value of a particular monitored parameter is outside the acceptable range specified in the parameter monitoring plan for the affected unit.

(u) Natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions. Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Equivalents of this in other units are as follows: 0.068 weight percent total sulfur, 680 parts per million by weight (ppmw) total sulfur, and 338 parts per million by volume (ppmv) at 20 degrees Celsius total sulfur. Additionally, natural gas must either be composed of at least 70 percent methane by

volume or have a gross calorific value between 950 and 1100 British thermal units (Btu) per standard cubic foot. Natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value.

(v) Duct burner means a device that combusts fuel and that is placed in the exhaust duct from another source, such as a stationary gas turbine, internal combustion engine, kiln, etc., to allow the firing of additional fuel to heat the exhaust gases before the exhaust gases enter a heat recovery steam generating unit.

(w) Lean premix stationary combustion turbine means any stationary combustion turbine where the air and fuel are thoroughly mixed to form a lean mixture for combustion in the combustor. Mixing may occur before or in the combustion chamber. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(x) Diffusion flame stationary combustion turbine means any stationary combustion turbine where fuel and air are injected at the combustor and are mixed only by diffusion prior to ignition. A unit which is capable of operating in both lean premix and diffusion flame modes is considered a lean premix stationary combustion turbine when it is in the lean premix mode, and it is considered a diffusion flame stationary combustion turbine when it is in the diffusion flame mode.

(y) Unit operating day means a 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time in the unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

§ 60.332 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraphs (b), (c), and (d) of this section shall comply with one of the following, except as provided in paragraphs (e), (f), (g), (h), (i), (j), (k), and (l) of this section.

(1) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0075\frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in Sec. 60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),
Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_X emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(2) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of:

$$STD = 0.0150\frac{(14.4)}{Y} + F$$

where:
STD = allowable ISO corrected (if required as given in Sec. 60.335(b)(1)) NO_X emission concentration (percent by volume at 15 percent oxygen and on a dry basis),
Y = manufacturer's rated heat rate at manufacturer's rated peak load (kilojoules per watt hour), or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and
F = NOX emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

(3) The use of F in paragraphs (a)(1) and (2) of this seciton is optional. That is, the owner or operator may choose to apply a NO_X allowance for fuel-bound nitrogen and determine the appropriate F-value in accordance with paragraph (a)(4) of this section or may accept an F-value of zero.

(4) If the owner or operator elects to apply a NO_X emission allowance for fuel-bound nitrogen, F shall be defined according to the nitrogen content of the fuel during the most recent performance test required under Sec. 60.8 as follows:

Fuel-bound nitrogen (% by weight)	F (NO_X% by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N-0.1)
$N > 0.25$	0.005

Where:
N = the nitrogen content of the fuel (percent by weight).or:
Manufacturers may develop and submit to EPA custom fuel-bound nitrogen allowances for each gas turbine model they manufacture. These fuel-bound nitrogen allowances shall be substantiated with data and must be approved for use by the Administrator before the initial performance test required by Sec. 60.8. Notices of approval of custom fuel-bound nitrogen allowances will be published in the Federal Register.

(b) Electric utility stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired shall comply with the provisions of paragraph (a)(1) of this section.

(c) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired, shall comply with the provisions of paragraph (a)(2) of this section.

(d) Stationary gas turbines with a manufacturer's rated base load at ISO conditions of 30 megawatts or less except as provided in § 60.332(b) shall comply with paragraph (a)(2) of this section.

(e) Stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules per hour (10 million Btu/hour) but less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) based on the lower heating value of the fuel fired and that have commenced construction prior to October 3, 1982 are exempt from paragraph (a) of this section.

(f) Stationary gas turbines using water or steam injection for control of NO_X emissions are exempt from paragraph (a) when ice fog is deemed a traffic hazard by the owner or operator of the gas turbine.

(g) Emergency gas turbines, military gas turbines for use in other than a garrison facility, military gas turbines installed for use as military training facilities, and fire fighting gas turbines are exempt from paragraph (a) of this section.

(h) Stationary gas turbines engaged by manufacturers in research and development of equipment for both gas turbine emission control techniques and gas turbine efficiency improvements are exempt from paragraph (a) on a case-by-case basis as determined by the Administrator.

(i) Exemptions from the requirements of paragraph (a) of this section will be granted on a case-by-case basis as determined by the Administrator in specific geographical areas where mandatory water restrictions are required by governmental agencies because of drought conditions. These exemptions will be allowed only while the mandatory water restrictions are in effect.

(j) Stationary gas turbines with a heat input at peak load greater than 107.2 gigajoules per hour that commenced construction, modification, or reconstruction between the dates of October 3, 1977, and January 27, 1982, and were required in the September 10, 1979, Federal Register (44 FR 52792) to comply with paragraph (a)(1) of this section, except electric utility stationary gas turbines, are exempt from paragraph (a) of this section.

(k) Stationary gas turbines with a heat input greater than or equal to 10.7 gigajoules per hour (10 million Btu/hour) when fired with natural gas are exempt from paragraph (a)(2) of this section when being fired with an emergency fuel.

(l) Regenerative cycle gas turbines with a heat input less than or equal to 107.2 gigajoules per hour (100 million Btu/hour) are exempt from paragraph (a) of this section.

§ 60.333 Standard for sulfur dioxide.

On and after the date on which the performance test required to be conducted by § 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with one or the other of the following conditions:

(a) No owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any stationary gas turbine any gases which contain sulfur dioxide in excess of 0.015 percent by volume at 15 percent oxygen and on a dry basis.

(b) No owner or operator subject to the provisions of this subpart shall burn in any stationary gas turbine any fuel which contains total sulfur in excess of 0.8 percent by weight (8000 ppmw).

§ 60.334 Monitoring of operations.

(a) Except as provided in paragraph (b) of this section, the owner or operator of any stationary gas turbine subject to the provisions of this subpart and using water or steam injection to control NO_X emissions shall install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine.

(b) The owner or operator of any stationary gas turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which uses water or steam injection to control NO_X emissions may, as an alternative to operating the continuous monitoring system described in paragraph (a) of this section, install, certify, maintain, operate, and quality-assure a continuous emission monitoring system (CEMS) consisting of NO_X and O2 monitors. As an alternative, a CO2 monitor may be used to adjust the measured NO_X concentrations to 15 percent O2 by either converting the CO2 hourly averages to equivalent O2 concentrations using Equation F-14a or F-14b in appendix F to part 75 of this chapter and making the adjustments to 15 percent O2, or by using the CO2 readings directly to make the adjustments, as described in Method 20. If the option to use a CEMS is chosen, the CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to PS 2 and 3 (for diluent) of 40 CFR part 60, appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. Appendix F, Procedure 1 is not required. The relative accuracy test audit (RATA) of the NO_X and diluent monitors may be performed individually or on a combined basis, i.e., the relative accuracy tests of the CEMS may be performed either:

(i) On a ppm basis (for NO_X) and a percent O2 basis for oxygen; or

(ii) On a ppm at 15 percent O2 basis; or

(iii) On a ppm basis (for NO_X) and a percent CO2 basis (for a CO2 monitor that uses the procedures in Method 20 to correct the NO_X data to 15 percent O2).

(2) As specified in Sec. 60.13(e)(2), during each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

(3) For purposes of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in Sec. 60.13(h).

(i) For each unit operating hour in which a valid hourly average, as described in paragraph (b)(2) of this section, is obtained for both NO_X and diluent, the data acquisition and handling system must calculate and record the hourly NO_X emissions in the units of the applicable NO_X emission standard under Sec. 60.332(a), i.e., percent NO_X by volume, dry basis, corrected to 15 percent O2 and International Organization for Standardization (ISO) standard conditions (if required as given in Sec. 60.335(b)(1)). For any hour in which the

hourly average O2 concentration exceeds 19.0 percent O2, a diluent cap value of 19.0 percent O2 may be used in the emission calculations.

(ii) A worst case ISO correction factor may be calculated and applied using historical ambient data. For the purpose of this calculation, substitute the maximum humidity of ambient air (Ho), minimum ambient temperature (Ta), and minimum combustor inlet absolute pressure (Po) into the ISO correction equation.

(iii) If the owner or operator has installed a NO_X CEMS to meet the requirements of part 75 of this chapter, and is continuing to meet the ongoing requirements of part 75 of this chapter, the CEMS may be used to meet the requirements of this section, except that the missing data substitution methodology provided for at 40 CFR part 75, subpart D, is not required for purposes of identifying excess emissions. Instead, periods of missing CEMS data are to be reported as monitor downtime in the excess emissions and monitoring performance report required in Sec. 60.7(c).

(c) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and which does not use steam or water injection to control NO_X emissions, the owner or operator may, for purposes of determining excess emissions, use a CEMS that meets the requirements of paragraph (b) of this section. Also, if the owner or operator has previously submitted and received EPA or local permitting authority approval of a petition for an alternative procedure of continuously monitoring compliance with the applicable NO_X emission limit under Sec. 60.332, that approved procedure may continue to be used, even if it deviates from paragraph (a) of this section.

(d) The owner or operator of any new turbine constructed after July 8, 2004, and which uses water or steam injection to control NO_X emissions may elect to use either the requirements in paragraph (a) of this section for continuous water or steam to fuel ratio monitoring or may use a NO_X CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section.

(e) The owner or operator of any new turbine that commences construction after July 8, 2004, and which does not use water or steam injection to control NO_X emissions may elect to use a NO_X CEMS installed, certified, operated, maintained, and quality-assured as described in paragraph (b) of this section. An acceptable alternative to installing a CEMS is described in paragraph (f) of this section.

(f) The owner or operator of a new turbine who elects not to install a CEMS under paragraph (e) of this section, may instead perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction controls (SCR), the owner or operator shall define at least four parameters indicative of the unit's NO_X formation characteristics and shall monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, the owner or operator shall continuously monitor the appropriate parameters to determine whether the unit is operating in the lean premixed (low-NO_X) combustion mode.

(3) For any turbine that uses SCR to reduce NO_X emissions, the owner or operator shall continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if the owner or operator elects to monitor NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in Sec. 75.19 of this chapter, the

requirements of this paragraph (f) may be met by performing the parametric monitoring described in section 2.3 of appendix E or in Sec. 75.19(c)(1)(iv)(H) of this chapter.

(g) The steam or water to fuel ratio or other parameters that are continuously monitored as described in paragraphs (a), (d) or (f) of this section shall be monitored during the performance test required under Sec. 60.8, to establish acceptable values and ranges. The owner or operator may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The owner or operator shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s) of the parameter(s) as well as the basis for designating the parameter(s) and acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer's recommendations and other relevant information shall be included in the monitoring plan. For affected units that are also subject to part 75 of this chapter and that use the low mass emissions methodology in Sec. 75.19 of this chapter or the NO_X emission measurement methodology in appendix E to part 75, the owner or operator may meet the requirements of this paragraph by developing and keeping on-site (or at a central location for unmanned facilities) a quality-assurance plan, as described in Sec. 75.19 (e)(5) or in section 2.3 of appendix E and section 1.3.6 of appendix B to part 75 of this chapter.

(h) The owner or operator of any stationary gas turbine subject to the provisions of this subpart:

(1) Shall monitor the total sulfur content of the fuel being fired in the turbine, except as provided in paragraph (h)(3) of this section. The sulfur content of the fuel must be determined using total sulfur methods described in Sec. 60.335(b)(10). Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than 0.4 weight percent (4000 ppmw), ASTM D4084-82, 94, D5504-01, D6228-98, or Gas Processors Association Standard 2377-86 (all of which are incorporated by reference-see Sec. 60.17), which measure the major sulfur compounds may be used; and

(2) Shall monitor the nitrogen content of the fuel combusted in the turbine, if the owner or operator claims an allowance for fuel bound nitrogen (i.e., if an F-value greater than zero is being or will be used by the owner or operator to calculate STD in Sec. 60.332). The nitrogen content of the fuel shall be determined using methods described in Sec. 60.335(b)(9) or an approved alternative.

(3) Notwithstanding the provisions of paragraph (h)(1) of this section, the owner or operator may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in Sec. 60.331(u), regardless of whether an existing custom schedule approved by the administrator for subpart GG requires such monitoring. The owner or operator shall use one of the following sources of information to make the required demonstration:

(i) The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20.0 grains/100 scf or less; or

(ii) Representative fuel sampling data which show that the sulfur content of the gaseous fuel does not exceed 20 grains/100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of appendix D to part 75 of this chapter is required.

(4) For any turbine that commenced construction, reconstruction or modification after October 3, 1977, but before July 8, 2004, and for which a custom fuel monitoring schedule has previously been approved, the owner or operator may, without submitting a special petition to the Administrator, continue monitoring on this schedule.

(i) The frequency of determining the sulfur and nitrogen content of the fuel shall be as follows:

(1) Fuel oil. For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of appendix D to part 75 of this chapter (i.e., flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank). If an emission allowance is being claimed for fuel-bound nitrogen, the nitrogen content of the oil shall be determined and recorded once per unit operating day.

(2) Gaseous fuel. Any applicable nitrogen content value of the gaseous fuel shall be determined and recorded once per unit operating day. For owners and operators that elect not to demonstrate sulfur content using options in paragraph (h)(3) of this section, and for which the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel shall be determined and recorded once per unit operating day.

(3) Custom schedules. Notwithstanding the requirements of paragraph (i)(2) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (i)(3)(i) and (i)(3)(ii) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in Sec. 60.333.

(i) The two custom sulfur monitoring schedules set forth in paragraphs (i)(3)(i)(A) through (D) and in paragraph (i)(3)(ii) of this section are acceptable, without prior Administrative approval:

(A) The owner or operator shall obtain daily total sulfur content measurements for 30 consecutive unit operating days, using the applicable methods specified in this subpart. Based on the results of the 30 daily samples, the required frequency for subsequent monitoring of the fuel's total sulfur content shall be as specified in paragraph (i)(3)(i)(B), (C), or (D) of this section, as applicable.

(B) If none of the 30 daily measurements of the fuel's total sulfur content exceeds 0.4 weight percent (4000 ppmw), subsequent sulfur content monitoring may be performed at 12 month intervals. If any of the samples taken at 12-month intervals has a total sulfur content between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), follow the procedures in paragraph (i)(3)(i)(C) of this section. If any measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section.

(C) If at least one of the 30 daily measurements of the fuel's total sulfur content is between 0.4 and 0.8 weight percent (4000 and 8000 ppmw), but none exceeds 0.8 weight percent (8000 ppmw), then:

(1) Collect and analyze a sample every 30 days for three months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(2) of this section.

(2) Begin monitoring at 6-month intervals for 12 months. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, follow the procedures in paragraph (i)(3)(i)(C)(3) of this section.

(3) Begin monitoring at 12-month intervals. If any sulfur content measurement exceeds 0.8 weight percent (8000 ppmw), follow the procedures in paragraph (i)(3)(i)(D) of this section. Otherwise, continue to monitor at this frequency.

(D) If a sulfur content measurement exceeds 0.8 weight percent

(8000 ppmw), immediately begin daily monitoring according to paragraph (i)(3)(i)(A) of this section. Daily monitoring shall continue until 30 consecutive daily samples, each having a sulfur content no greater than 0.8 weight percent (8000 ppmw), are obtained. At that point, the applicable procedures of paragraph (i)(3)(i)(B) or (C) of this section shall be followed.

(ii) The owner or operator may use the data collected from the 720-hour sulfur sampling demonstration described in section 2.3.6 of appendix D to part 75 of this chapter to determine a custom sulfur sampling schedule, as follows:

(A) If the maximum fuel sulfur content obtained from the 720 hourly samples does not exceed 20 grains/100 scf (i.e., the maximum total sulfur content of natural gas as defined in Sec. 60.331(u)), no additional monitoring of the sulfur content of the gas is required, for the purposes of this subpart.

(B) If the maximum fuel sulfur content obtained from any of the 720 hourly samples exceeds 20 grains/100 scf, but none of the sulfur content values (when converted to weight percent sulfur) exceeds 0.4 weight percent (4000 ppmw), then the minimum required sampling frequency shall be one sample at 12 month intervals.

(C) If any sample result exceeds 0.4 weight percent sulfur (4000 ppmw), but none exceeds 0.8 weight percent sulfur (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(C) of this section.

(D) If the sulfur content of any of the 720 hourly samples exceeds 0.8 weight percent (8000 ppmw), follow the provisions of paragraph (i)(3)(i)(D) of this section.

(j) For each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content or fuel nitrogen content under this subpart, the owner or operator shall submit reports of excess emissions and monitor downtime, in accordance with Sec. 60.7(c). Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. For the purpose of reports required under Sec. 60.7(c), periods of excess emissions and monitor downtime that shall be reported are defined as follows:

(1) Nitrogen oxides.

(i) For turbines using water or steam to fuel ratio monitoring:

(A) An excess emission shall be any unit operating hour for which the average steam or water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable steam or water to fuel ratio needed to demonstrate compliance with Sec. 60.332, as established during the performance test required in Sec. 60.8. Any unit operating hour in which no water or steam is injected into the turbine shall also be considered an excess emission.

(B) A period of monitor downtime shall be any unit operating hour in which water or steam is injected into the turbine, but the essential parametric data needed to determine the steam or water to fuel ratio are unavailable or invalid.

(C) Each report shall include the average steam or water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity), gas turbine load, and (if applicable) the nitrogen content of the fuel during each excess emission. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in Sec. 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of Sec. 60.335(b)(1).

(ii) If the owner or operator elects to take an emission allowance for fuel bound nitrogen, then excess emissions and periods of monitor downtime are as described in paragraphs (j)(1)(ii)(A) and (B) of this section.

(A) An excess emission shall be the period of time during which the fuel-bound nitrogen (N) is greater than the value measured during the performance test required in Sec. 60.8 and used to determine the allowance. The excess emission begins on the

date and hour of the sample which shows that N is greater than the performance test value, and ends with the date and hour of a subsequent sample which shows a fuel nitrogen content less than or equal to the performance test value.

(B) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour that a required sample is taken, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

(iii) For turbines using NO_X and diluent CEMS:

(A) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_X concentration exceeds the applicable emission limit in Sec. 60.332(a)(1) or (2). For the purposes of this subpart, a ``4-hour rolling average NO_X concentration'' is the arithmetic average of the average NO_X concentration measured by the CEMS for a given hour (corrected to 15 percent O2 and, if required under Sec. 60.335(b)(1), to ISO standard conditions) and the three unit operating hour average NO_X concentrations immediately preceding that unit operating hour.

(B) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_X concentration or diluent (or both).

(C) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period and (if the owner or operator has claimed an emission allowance for fuel bound nitrogen) the nitrogen content of the fuel during the period of excess emissions. You do not have to report ambient conditions if you opt to use the worst case ISO correction factor as specified in Sec. 60.334(b)(3)(ii), or if you are not using the ISO correction equation under the provisions of Sec. 60.335(b)(1).

(iv) For turbines required under paragraph (f) of this section to monitor combustion parameters or parameters that document proper operation of the NO_X emission controls:

(A) An excess emission shall be a 4-hour rolling unit operating hour average in which any monitored parameter does not achieve the target value or is outside the acceptable range defined in the parameter monitoring plan for the unit.

(B) A period of monitor downtime shall be a unit operating hour in which any of the required parametric data are either not recorded or are invalid.

(2) Sulfur dioxide. If the owner or operator is required to monitor the sulfur content of the fuel under paragraph (h) of this section:

(i) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 weight percent and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(ii) If the option to sample each delivery of fuel oil has been selected, the owner or operator shall immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.8 weight percent. The owner or operator shall continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and shall evaluate excess emissions according to paragraph (j)(2)(i) of this section. When all of the fuel from the delivery has been burned, the owner or operator may resume using the as-delivered sampling option.

(iii) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a

required sample, if invalid results are obtained. The period of monitor downtime shall include only unit operating hours, and ends on the date and hour of the next valid sample.

(3) *Ice fog.* Each period during which an exemption provided in § 60.332(f) is in effect shall be reported in writing to the Administrator quarterly. For each period the ambient conditions existing during the period, the date and time the air pollution control system was deactivated, and the date and time the air pollution control system was reactivated shall be reported. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter.

(4) *Emergency fuel.* Each period during which an exemption provided in § 60.332(k) is in effect shall be included in the report required in § 60.7(c). For each period, the type, reasons, and duration of the firing of the emergency fuel shall be reported.

(5) All reports required under Sec. 60.7(c) shall be postmarked by the 30th day following the end of each calendar quarter.

Sec. 60.335 Test methods and procedures.

(a) The owner or operator shall conduct the performance tests required in Sec. 60.8, using either

(1) EPA Method 20,

(2) ASTM D6522-00 (incorporated by reference, see Sec. 60.17), or

(3) EPA Method 7E and either EPA Method 3 or 3A in appendix A to this part, to determine NO_X and diluent concentration.

(4) Sampling traverse points are to be selected following Method 20 or Method 1, (non-particulate procedures) and sampled for equal time intervals. The sampling shall be performed with a traversing single-hole probe or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

(5) Notwithstanding paragraph (a)(4) of this section, the owner or operator may test at few points than are specified in Method 1 or Method 20 if the following conditions are met:

(i) You may perform a stratification test for NO_X and diluent pursuant to

(A) [Reserved]

(B) The procedures specified in section 6.5.6.1(a) through (e) appendix A to part 75 of this chapter.

(ii) Once the stratification sampling is completed, the owner or operator may use the following alternative sample point selection criteria for the performance test:

(A) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O2, is within 10 percent of the mean normalized concentration for all traverse points, then you may use 3 points (located either 16.7, 50.0, and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at 0.4, 1.2, and 2.0 meters from the wall). The 3 points shall be located along the measurement line that exhibited the highest average normalized NO_X concentration during the stratification test; or

(B) If each of the individual traverse point NO_X concentrations, normalized to 15 percent O2, is within 5 percent of the mean normalized concentration for all traverse points, then you may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid.

(6) Other acceptable alternative reference methods and procedures are given in paragraph (c) of this section.

(b) The owner or operator shall determine compliance with the applicable nitrogen oxides emission limitation in Sec. 60.332 and shall meet the performance test requirements of Sec. 60.8 as follows:

(1) For each run of the performance test, the mean nitrogen oxides emission concentration (NO_{Xo}) corrected to 15 percent O2 shall be corrected to ISO standard conditions using the following equation. Notwithstanding this requirement, use of the ISO correction equation is optional for: Lean premix stationary combustion turbines; units used in association with heat recovery steam generators (HRSG) equipped with duct burners; and units equipped with add-on emission control devices:

$$NO_X=(NO_{Xo})(P_r/P_o)^{0.5}\, e^{19\,(H_o-0.00633)}\,(288[\text{deg}]K/Ta)^{1.53}$$

Where:
NO_X = emission concentration of NO_X at 15 percent O2 and ISO standard ambient conditions, ppm by volume, dry basis,
NO_{Xo} = mean observed NO_X concentration, ppm by volume, dry basis, at 15 percent O2,
P_r = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg,
P_o = observed combustor inlet absolute pressure at test, mm Hg,
H_o = observed humidity of ambient air, g H2O/g air,
e = transcendental constant, 2.718, and
T_a = ambient temperature, [deg]K.

(2) The 3-run performance test required by Sec. 60.8 must be performed within 5 percent at 30, 50, 75, and 90-to-100 percent of peak load or at four evenly-spaced load points in the normal operating range of the gas turbine, including the minimum point in the operating range and 90-to-100 percent of peak load, or at the highest achievable load point if 90-to-100 percent of peak load cannot be physically achieved in practice. If the turbine combusts both oil and gas as primary or backup fuels, separate performance testing is required for each fuel. Notwithstanding theserequirements, performance testing is not required for any emergency fuel (as defined in Sec. 60.331).

(3) For a combined cycle turbine system with supplemental heat (duct burner), the owner or operator may elect to measure the turbine NO_X emissions after the duct burner rather than directly after the turbine. If the owner or operator elects to use this alternative sampling location, the applicable NO_X emission limit in Sec. 60.332 for the combustion turbine must still be met.

(4) If water or steam injection is used to control NO_X with no additional post-combustion NO_X control and the owner or operator chooses to monitor the steam or water to fuel ratio in accordance with Sec. 60.334(a), then that monitoring system must be operated concurrently with each EPA Method 20, ASTM D6522-00 (incorporated by reference, see Sec. 60.17), or EPA Method 7E run and shall be used to determine the fuel consumption and the steam or water to fuel ratio necessary to comply with the applicable Sec. 60.332 NO_X emission limit.

(5) If the owner operator elects to claim an emission allowance for fuel bound nitrogen as described in Sec. 60.332, then concurrently with each reference method run, a representative sample of the fuel used shall be collected and analyzed, following the applicable procedures described in Sec. 60.335(b)(9). These data shall be used to determine the maximum fuel nitrogen content for which the established water (or steam) to fuel ratio will be valid.

(6) If the owner or operator elects to install a CEMS, the performance evaluation of the CEMS may either be conducted separately (as described in paragraph (b)(7) of this section) or as part of the initial performance test of the affected unit.

(7) If the owner or operator elects to install and certify a NO_X CEMS under Sec. 60.334(e), then the initial performance test required under Sec. 60.8 may be done in the following alternative manner:

(i) Perform a minimum of 9 reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest physically achievable) load.

(ii) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under Sec. 60.332 and to provide the required reference method data for the RATA of the CEMS described under Sec. 60.334(b).

(iii) The requirement to test at three additional load levels is waived.

(8) If the owner or operator is required under Sec. 60.334(f) to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls, the appropriate parameters shall be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit, as specified in Sec. 60.334(g).

(9) To determine the fuel bound nitrogen content of fuel being fired (if an emission allowance is claimed for fuel bound nitrogen), the owner or operator may use equipment and procedures meeting the requirements of:

(i) For liquid fuels, ASTM D2597-94 (Reapproved 1999), D6366-99, D4629-02, D5762-02 (all of which are incorporated by reference, see Sec. 60.17); or

(ii) For gaseous fuels, shall use analytical methods and procedures that are accurate to within 5 percent of the instrument range and are approved by the Administrator.

(10) If the owner or operator is required under Sec. 60.334(i)(1) or (3) to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples shall be collected during the performance test. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129-00, D2622-98, D4294-02, D1266-98, D5453-00 or D1552-01 (all of which are incorporated by reference, see Sec. 60.17); or

(ii) For gaseous fuels, ASTM D1072-80, 90 (Reapproved 1994); D3246-81, 92, 96; D4468-85 (Reapproved 2000); or D6667-01 (all of which are incorporated by reference, see Sec. 60.17). The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the prior approval of the Administrator.

(11) The fuel analyses required under paragraphs (b)(9) and (b)(10) of this section may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

(c) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) Instead of using the equation in paragraph (b)(1) of this section, manufacturers may develop ambient condition correction factors to adjust the nitrogen oxides emission level measured by the performance test as provided in Sec. 60.8 to ISO standard day conditions.

Appendix 2: Air Construction Permit PSD-FL-254

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the Matter of an
Application for Permit by:

Mr. A. K. Sharma, Director of Power Supply
Kissimmee Utility Authority
1701 West Carroll Street
Kissimmee, Florida 34741-6804

Facility I.D. No. 0970043
DRAFT Permit No.: PSD-FL-254
Cane Island Power Park Unit 3
Osceola County

_____/

Enclosed is the Final Permit Number PSD-FL-254 to construct: a nominal 250 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine-electrical generator; a supplementally-fired heat recovery steam generator; a steam electrical generator; a 1.0 million gallon fuel oil storage tank; ammonia storage; 130-foot main stack; and a 100-foot bypass stack at the Kissimmee Utility Authority Cane Island Power Park at 6075 Old Tampa Highway, Osceola County. This permit is issued pursuant to Chapter 403, Florida Statutes and 40CFR52.21.

Any party to this order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, F.S., by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Legal Office; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 (thirty) days from the date this Notice is filed with the Clerk of the Department.

In addition to the appeal process described above, federal appeals procedures concerning this PSD permit are outlined in 40CFR 124.19, which is attached. Any person who filed comments on the draft permit may petition the Environmental Appeals Board to review any condition of the permit decision. Any person who failed to file comments on the draft permit may petition for administrative review only to the extent of the changes from the draft to the final permit decision.

The petition must be filed with the Environmental Appeals Board within 30 days of issuance of this Notice. Petitions may be addressed to the Environmental appeals Board, MC 1103B, U.S. Environmental Protection Agency, 401 M Street, Washington, D.C. 20460. Further details are available at www.epa.gov/eab.

Executed in Tallahassee, Florida.

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

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF FINAL PERMIT (including the FINAL permit) was sent by certified mail* and copies were mailed by U.S. Mail before the close of business on 11-24-99 to the person(s) listed:

A. K. Sharma, KUA*
Jeff Ling, KUA
Gregg Worley, EPA
John Bunyak, NPS
Len Kozlov, DEP CD
Buck Oven, DEP PPSO
D. D. Schultz, P.E., Black & Veatch
Tasha Buford, Esq., YVVA, P.A.

Clerk Stamp

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

Lynn Tiber (Clerk) 11-24-99 (Date)

Department of Environmental Protection

Jeb Bush
Governor

Marjory Stoneman Douglas Building
3900 Commonwealth Boulevard
Tallahassee, Florida 32399-3000

David B. Struhs
Secretary

PERMITTEE:

Kissimmee Utility Authority (KUA)
1701 West Carroll Street
Kissimmee, Florida 34741-6804

File No.	PSD-FL-254 (PA98-38)
FID No.	0970043
SIC No.	4911
Expires:	December 31, 2002

Authorized Representative:

A.K. Sharma, Director of Power Supply

PROJECT AND LOCATION:

Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: a nominal 167 megawatt (MW) gas-fired, stationary combustion turbine-electrical generator; a supplementally-fired heat recovery steam generator (HRSG); a nominal 80-90 MW steam electrical generator; a 1.0 million gallon storage tank for back-up distillate fuel oil; a selective catalytic reduction unit and ancillary equipment; ammonia storage; a 130-foot stack; and a 100-foot bypass stack for simple cycle operation. The unit will achieve approximately 250 megawatt in combined cycle operation at referenced conditions. The unit is designated as Unit 3 and will be located at the Cane Island Power Park, 6075 Old Tampa Highway, near Intercession City, Osceola County. UTM coordinates are: Zone 17; 447.72 km E; 3127.68 km N.

STATEMENT OF BASIS:

This PSD permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.) and 40CFR52.21. The above named permittee is authorized to modify the facility in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department of Environmental Protection (Department).

The attached Appendix is made a part of this permit:

Appendix GC Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources Management

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

The existing Kissimmee Utility Authority (KUA) Cane Island Power Park consists of a nominal 40 MW simple cycle combustion turbine designated as Unit 1 and a nominal 120 MW combined cycle combustion turbine-electrical generator with a heat recovery steam generator (HRSG) and a steam electrical generator designated as Unit 2.

The proposed KUA Cane Island Power Park Unit 3 is a nominal 250 MW combined cycle plant. It will include: 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. New major support facilities for Unit 3 include a cooling tower, water and wastewater facilities, water storage tanks, storm water detention pond, 230 KV transmission line, and a 1.0 million gallon storage tank for back-up distillate fuel oil.

Emissions from Cane Island Power Park Unit 3 will be controlled by Dry Low NO_X (DLN) combustors or wet injection under simple cycle operation. Emissions will be controlled by DLN or wet injection and selective catalytic reduction (SCR) when operating in combined cycle mode. Inherently clean fuels and good combustion practices will be employed to control all pollutants.

EMISSION UNITS

This permit addresses the following emission units:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
003	Power Generation	One nominal 167 Megawatt Gas Combustion Turbine-Electrical Generator
004	Fuel Storage	1.0 Million Gallon Fuel Oil Storage Tank
005	Steam Generation	One 44 mmBtu/hr Duct Burner in a Supplementally Fired Heat Recovery Steam Generator (and 80-90 MW Steam Electrical Turbine)
006	Water Cooling	Cooling Tower

REGULATORY CLASSIFICATION

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

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-254

SECTION I - FACILITY INFORMATION

This facility is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. Because emissions are greater than 100 TPY for at least one criteria pollutant, the facility is also a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD). Pursuant to Table 62-212.400-2, this facility modification results in emissions increases greater than 40 TPY of NO_X , 25/15 TPY of PM/PM_{10}, 100 TPY of CO and 40 TPY of VOCs. These pollutants require review per the PSD rules and a determination for Best Available Control Technology (BACT) per Rule 62-212.400, F.A.C.

This Project is subject to the applicable requirements of Chapter 403. Part II, F.S., Electric Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility is greater than 75 MW. [Chapter 403.503 (12), F.S., Definitions]

This facility is also subject to certain Acid Rain provisions of Title IV of the Clean Air Act.

PERMIT SCHEDULE

- 11/23/99 PSD Permit Issued
- 11/22/99 Site Certification Issued
- 01/09/99 Notice of Intent to Issue PSD Permit published in The Orlando Sentinel
- 01/07/99 Distributed Intent to Issue Permit
- 08/05/98 Received PSD Application

RELEVANT DOCUMENTS:

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

- Application received on August 5, 1998
- Department/BAR letters to KUA dated August 17, and September 23, 1998
- Comments from the Fish and Wildlife Service dated September 11, 1998
- KUA letters (through Black & Veatch) dated November 6 and November 30, 1998 and January 6, February 3, February 12, March 10, and March 24, 1999.
- Department's Intent to Issue and Public Notice Package dated January 8, 1999.
- Department's revised Draft Permit and BACT determination dated March 25, 1999.
- Letters from EPA Region IV dated February 2, February 10, and November 8, 1999.
- Black & Veatch and GE Presentations to Department and EPA Region IV on March 4, 1999.
- Site Certification for the KUA Cane Island Facility approved November 22, 1999.
- Department's Final Determination and Best Available Control Technology Determination issued concurrently with this Final Permit.

GENERAL AND ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blairstone Road, Tallahassee, Florida 32399-2400 and phone number (850)488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Central District Office, 3319 Maguire Boulevard, Suite 232, Orlando, Florida 32803-3767 and phone number 407/894-7555.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]
6. Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [40 CFR 52.21(r)(2)]
7. BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction, or extension of the December 31, 2002 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [40 CFR 52.21(j)(4)]
8. Permit Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.080, F.A.C.).

9. Application for Title IV Permit: An application for a Title IV Acid Rain Permit, must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which the new unit begins serving an electrical generator (greater than 25 MW). [40 CFR 72]

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

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

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

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

14. Quarterly Reports: Quarterly excess emission reports, in accordance with 40 CFR 60.7 (a)(7) (c) (1998 version), shall be submitted to the DEP's Central District Office.

APPLICABLE STANDARDS AND REGULATIONS:

1. Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations Section 40, Parts 52, 60, 72, 73, and 75.
2. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]
3. These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:
   - 40CFR60.7, Notification and Recordkeeping
   - 40CFR60.8, Performance Tests
   - 40CFR60.11, Compliance with Standards and Maintenance Requirements
   - 40CFR60.12, Circumvention
   - 40CFR60.13, Monitoring Requirements
   - 40CFR60.19, General Notification and Reporting requirements
4. ARMS Emissions Unit 003. Direct Power Generation, consisting of a nominal 167 megawatt combustion turbine-electrical generator, shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s).
5. ARMS Emission Unit 004. Fuel Storage, consisting of a 1.0 million gallon distillate fuel oil storage tank shall comply with all applicable provisions of 40CFR60, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, adopted by reference in Rule 62-204.800, F.A.C.
6. ARMS Emission Unit 005. Steam Power Generation, consisting of a supplementally-fired heat recovery steam generator equipped with a natural gas fired 44 mmBTU/hr duct burner (HHV) and 80-90 MW steam electrical generator shall comply with all applicable provisions of 40CFR60, Subpart Dc, Standards of Performance for Small Industrial Commercial-Institutional Steam Generating Units Which Construction is Commenced After September June 9, 1989, adopted by reference in Rule 62-204.800(7), F.A.C.
7. ARMS Emission Unit 006. Cooling Tower, is an unregulated emission unit. The Cooling Tower is not subject to a NESHAP because Chromium-based chemical treatment is not used.
8. All notifications and reports required by the above specific conditions shall be submitted to the DEP's Central District Office.

GENERAL OPERATION REQUIREMENTS

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

10. Combustion Turbine Capacity: The maximum heat input rates, based on the lower heating value (LHV) of each fuel to this Unit at ambient conditions of 19°F temperature, 55% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,696 million Btu per hour (mmBtu/hr) when firing natural gas, nor 1,910 mmBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

11. Heat Recovery Steam Generator equipped with Duct Burner. The maximum heat input rate of the natural gas fired duct burner shall not exceed 44 mmBtu/hour (HHV). [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

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

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

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

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

16. Maximum allowable hours of operation for the 250 MW Combined Cycle Plant are 8760 hours per year while firing natural gas. Fuel oil firing of the combustion turbine is permitted for a maximum of 720 hours per year. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

17. Simple Cycle Operation The plant may be operated in simple cycle mode. Different limits apply depending upon whether simple cycle operation is of an intermittent nature, such as: caused by maintenance of equipment following the combustion turbine; temporary electrical demand fluctuations; a decision to not install the heat recovery steam generator; or long term electrical demand situations.

CONTROL TECHNOLOGY

18. Dry Low NO_X (DLN) combustors shall be installed on the stationary combustion turbine to comply with the simple cycle NO_X emissions limits listed in Specific Condition 24. [Design, Rules 62-4.070 and 62-212.400, F.A.C.]

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

20. The permittee shall install selective catalytic reduction system to comply with the combined cycle NO_X limit listed in Specific Condition 24.

21. The permittee shall design these units to accommodate adequate testing and sampling locations for compliance with the applicable emission limits (per each unit) listed in Specific Conditions No. 24 through 28. [Rule 62-4.070 , Rule 62-204.800, F.A.C., and 40 CFR60.40a(b)]

22. The permittee shall provide manufacturer's emissions performance versus load diagrams for the DLN and wet injection systems prior to their installation. DLN systems shall each be tuned upon initial operation to optimize emissions reductions and shall be maintained to minimize simple cycle NO_X emissions and CO emissions. [Rule 62-4.070, and 62-210.650 F.A.C.]

23. Drift eliminators shall be installed on the cooling tower to reduce PM/PM_{10} emissions.

EMISSION LIMITS AND STANDARDS

24. Nitrogen Oxides (NO_X) Emissions:

A. Combined Cycle Operation

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas (fuel oil) and the duct burner on or off, shall not exceed 3.5 (15) ppmvd @15% O_2 on a 3-hr block average. Compliance shall be determined by the continuous emission monitor (CEMS). Emissions of NO_X calculated as NO_2 in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 26 (108) pounds per hour (lb/hr) with the duct burner on or off to be demonstrated by initial stack test. [Applicant Request on November 9, 1999]

- The concentration of ammonia in the exhaust gas from each combustion turbine shall not exceed 5 ppmvd @15% O_2. The compliance procedures are described in Specific Condition 52. [Rules 62-212.400 and 62-4.070, F.A.C.]
- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

B. Intermittent Simple Cycle Operation

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas (fuel oil) shall not exceed 12 (42) ppmvd at 15% O_2 (24-hr block average). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 86 (310) pounds per hour (lb/hr). [Rules 62-212.400, F.A.C.]
- Notwithstanding the applicable NO_X limit during simple cycle operation, reasonable measures shall be implemented to maintain the concentration of NO_X in the exhaust gas at 9 ppmvd at 15% O_2 or lower. Any tuning of the combustors for Dry Low NO_X operation while firing gas shall result in initial subsequent NO_X concentrations of 9 ppmvd @15% O_2 or lower. [Rules 62-212.400 and 62-4.070, F.A.C.]
- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

C. Continuous Simple Cycle Operation

- The concentration of NO_X in the stack exhaust gas, with the combustion turbine operating on gas (fuel oil) shall not exceed 9 (42) ppmvd at 15% O_2 (24-hr block average). Emissions of NO_X in the stack exhaust gas (at ISO conditions) with the combustion turbine operating shall not exceed 65 (310) pounds per hour (lb/hr). [Rules 62-212.400, F.A.C.]
- Notwithstanding the applicable NO_X limit during simple cycle operation, reasonable measures shall be implemented to maintain the concentration of NO_X in the exhaust gas at 9 ppmvd at 15% O_2 or lower. Any tuning of the combustors for Dry Low NO_X operation while firing gas shall result in initial subsequent NO_X concentrations of 9 ppmvd @15% O_2 or lower. [Rules 62-212.400 and 62-4.070, F.A.C.]
- When NO_X monitoring data is not available, substitution for missing data shall be handled as required by Title IV (40 CFR 75) to calculate any specified average time.

25. Carbon Monoxide (CO) Emissions: Emissions of CO in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas (fuel oil) shall exceed neither 12 (20) ppm nor 43 (71) lb/hr with the duct burner off and neither 20 (30) ppm nor 71 (108) lb/hr with the duct burner on to be demonstrated by stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

26. Volatile Organic Compounds (VOC) Emissions: Emissions of VOC in the stack exhaust gas (at ISO conditions) with the combustion turbine operating on gas (fuel oil) shall exceed neither 1.4 (10) ppm nor 3 (21.4) lb/hr with the duct burner off and neither 4 (10) ppm nor 8.5 (21.4)

lb/hr with the duct burner on to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Rule 62-212.400, F.A.C.]

27. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 20 grains per 100 standard cubic foot) or by firing No. 2 or superior grade distillate fuel oil with a maximum 0.05 percent sulfur for 720 hours per year. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions 48 and 49 will demonstrate compliance with the applicable NSPS SO_2 emissions limitations from the duct burner or the combustion turbine. Emissions of SO_2 shall not exceed 38.1 tons per year. [40CFR60 Subpart GG and Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C. to avoid PSD Review]

28. Visible emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine operating with or without the duct burner and shall not exceed 10 percent opacity from the stack in use. [Rules 62-4.070, 62-212.400, and 62-204.800(7), F.A.C.]

EXCESS EMISSIONS

29. Excess emissions resulting from startup, shutdown, or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except during both "cold start-up" to or shutdowns from combined cycle plant operation. During start-up to simple cycle operation, up to one hour of excess emissions are allowed. During cold start-up to combined cycle operation, up to four hours of excess emissions are allowed. During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed. Cold start-up is defined as a startup to combined cycle operation following a complete shutdown lasting at least 48 hours. [Applicant Request, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.].

30. Excess emissions entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. These emissions shall be included in the 24-hr average for NO_X.

31. Excess Emissions Report: If excess emissions occur for more than two hours due to malfunction, the owner or operator shall notify DEP's Central District office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following this format, 40 CFR 60.7, periods of startup, shutdown, malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 24. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1998 version)].

COMPLIANCE DETERMINATION

32. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate, but not later than 180 days of initial operation of the unit, and annually thereafter as indicated in this permit, by using the following reference methods as described in 40 CFR 60, Appendix A (1998 version), and adopted by reference in Chapter 62-204.800, F.A.C.

33. Initial (I) performance tests (for both fuels) shall be performed by the deadlines in Specific Condition 32. Initial tests shall also be conducted after any substantial modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as installation of SCR or change of combustors. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on these units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A).
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (I, A).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Test must be conducted with the duct burner on and with the duct burner off.
- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.
- EPA Method 26A (modified) for ammonia sample collection
- EPA Draft Method 206 for ion chromatographic analysis for ammonia.

34. Continuous compliance with the NO_X emission limits: Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system on a 3-hr average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each 3-hr period and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous 3-hr period. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless prohibited by 62-210.700 F.A.C. 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. These excess emissions periods shall be reported as required in Condition 31. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., 40 CFR 75 and BACT]

35. Compliance with the SO_2 and PM/PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas, is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur

content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1998 version).

36. Compliance with CO emission limit: An initial test for CO, shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance testing is conducted concurrent with the annual RATA testing for the NO_X CEMS required pursuant to 40 CFR 75. Alternatively to annual testing in a given year, periodic tuning data may be provided to demonstrate compliance in the year the tuning is conducted.

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

38. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C.

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

40. Special Compliance Tests: The DEP may request a special compliance test pursuant to Rule 62-297.310(7), F.A.C., when, after investigation (such as complaints, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emission standard is being violated.

41. Test Results: Compliance test results shall be submitted to the DEP's Central District office no later than 45 days after completion of the last test run. [Rule 62-297.310(8), F.A.C.].

NOTIFICATION, REPORTING, AND RECORDKEEPING

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

43. Compliance Test Reports: The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8), F.A.C.

MONITORING REQUIREMENTS

44. Continuous Monitoring System: The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen from these units. Periods when NO_X emissions (ppmvd @ 15% oxygen) are above the permitted limits, listed in Specific Condition No. 24, shall be reported to the DEP Central District Office within one working day (verbally) followed up by a written explanation not later than three (3) working days (alternatively by facsimile within one working day). [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1998 version)].

45. CEMS for reporting excess emissions: The NO_X CEMS shall be used in lieu of the requirement for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). Upon request from DEP, the CEMS emission rates for NO_X on the CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [EPA Approval dated February10, 1999]

46. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1998 version). Subject to EPA approval, the calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1998 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS. Upon request from DEP, the CEMS emission rates for NO_X on this Unit shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [EPA Approval dated February10, 1999]

47. Continuous Monitoring System Reports: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

48. Natural Gas Monitoring Schedule: A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

    - The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
    - The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of pipeline supplied natural gas (sulfur content less than 20 gr/100 scf pursuant to 40 CFR 75.11(d)(2)).
    - Each unit shall be monitored for SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

    This custom fuel monitoring schedule will only be valid when pipeline natural gas is used as a primary fuel. If the primary fuel for these units is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

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

50. Determination of Process Variables:

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

51. Subpart Dc Monitoring and Recordkeeping Requirements: The permittee shall comply with all applicable requirements of this Subpart [40CFR60, Subpart Dc].

52. Selective Catalytic Reduction System (SCR) Compliance Procedures:

    - An initial stack emission test for nitrogen oxides and ammonia from the CGT/HRGS pair shall be conducted: 1) for natural gas firing and 2) for distillate fuel oil firing. The ammonia injection rate necessary to comply with the NO_X standard shall be established during the initial performance tests.

- The SCR shall operate at all times that the turbine is operating, except during turbine start-up and shutdown periods. During turbine start-up, permittee shall begin use of SCR (i.e., commence ammonia injection) within two (2) hours of the initial turbine firing or when the temperature of the catalyst bed reaches a suitable predetermined temperature level, whichever occurs first. During turbine shutdown, permittee shall discontinue use of the SCR (i.e., discontinue ammonia injection) when the catalyst bed temperature drops below the predetermined temperature levels, but no more than one hour prior to the time at which the fuel feed to the turbine is discontinued. Suitable temperature for activation and deactivation of the SCR shall be established during performance testing. The permittee shall, whenever possible, operate the facility in a manner so as to optimize the effectiveness of the SCR unit while minimizing ammonia slip to below the emission limit.
- The permittee shall install and operate an ammonia flow meter to measured and record the ammonia injection rate to the SCR system of the CGT/HRSG set. It shall be maintained and calibrated according to the manufacture's specifications. During the stack test, the permittee at each load condition shall determine the minimum ammonia flow rate required to meet the emissions limitations. During NO_X CEM downtimes or malfunctions, the permittee shall operate at greater or equal to 100% of the ammonia injection rate determined during the stack test.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

G.13 This permit also constitutes:

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

G.14 The permittee shall comply with the following:

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

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

c) Records of monitoring information shall include:

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

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

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

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

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.

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
NG = Natural Gas
FO = Fuel Oil
DLN = Dry Low NO_X Combustion
SCR = Selective Catalytic Reduction
WI = Water or Steam Injection
GE = General Electric
WH = Westinghouse
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.

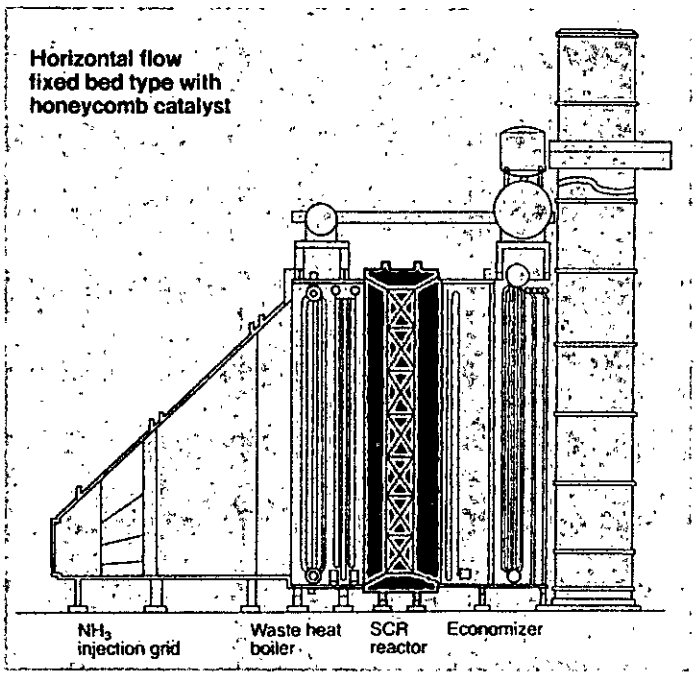

Figure 7 – SCR System within HRSG

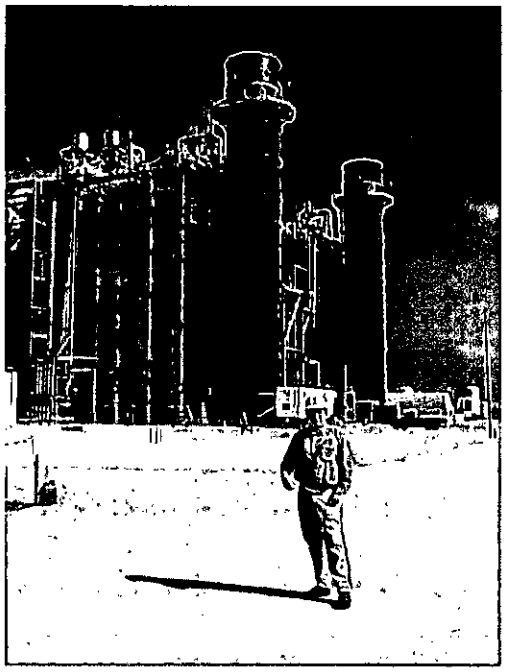

Figure 8 – FPC Hines Power Block I

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. ABB Environmental was announced on September 10, 1998 as the exclusive licensee for SCONOx™ for United States turbine applications larger than 100 MW. ABB Power Generation 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.

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

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

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and will be used for approximately 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.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

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

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 11/22
Teresa Heron, Review Engineer, New Source Review Section
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By:

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

Date: 11/23/99

Approved By:

Howard L. Rhodes, Director
Division of Air Resources Management

Date: 11/23/99

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Appendix 3: Air Construction Permit PSD-FL-400

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor
Jeff Kottkamp
Lt. Governor
Michael W. Sole
Secretary

PERMITTEE

Florida Municipal Power Agency (FMPA)
8553 Commodity Circle
Orlando, Florida 32819

Authorized Representative:
Mr. Roger Fontes
General Manager and CEO

Air Permit No. PSD-FL-400
Air Permit No. 0970043-014-AC
Cane Island Power Park
Combined Cycle Unit 4
Osceola County, Florida
Expires: August 31, 2012

PROJECT AND LOCATION

This permit authorizes the construction of a nominal 300 megawatts (MW) natural gas-fueled combined cycle unit (Unit 4) at the existing Cane Island Power Park. The project consists of: a nominal 150 MW General Electric 7FA combustion turbine-electrical generator; a duct fired heat recovery steam generator; a nominal 150 MW steam-electrical generator; a nominal 160-foot stack; a mechanical draft cooling tower with drift eliminators; and two diesel engines with ultralow sulfur diesel fuel oil storage tanks.

The facility is located at 6075 Old Tampa Highway, Intercession City in Osceola County. The UTM coordinates for this site are 447.5 km East and 3128.0 North.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296 and 62-297 of the Florida Administrative Code (F.A.C.) and Title 40, Parts 60 and 63 of the Code of Federal Regulations (CFR). The permittee is authorized to install the proposed equipment in accordance with the conditions of this permit and as described in the application, approved drawings, plans, and other documents on file with the Department.

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Section 1. General Information
Section 2. Administrative Requirements
Section 3. Emissions Units Specific Conditions
Section 4. Appendices

Joseph Kahn, Director
Division of Air Resource Management

9/5/08
(Date)

FACILITY AND PROJECT DESCRIPTION

The existing Cane Island Power Park (CIPP) facility consists of:

- Unit 1 – a 40 megawatts (MW) simple cycle combustion turbine-electric generator (CTG);
- Unit 2 - a 120 MW combined cycle unit including a CTG, a heat recovery steam generator (HRSG) and steam turbine –electric generator (STG); and
- Unit 3 - a 250 MW combined cycle unit including a CTG, HRSG and STG.

The project will be a "one-on-one" 300 MW natural gas-fueled combined cycle unit (CIPP Unit 4) and associated auxiliary equipment. Unit 4 and associated auxiliary equipment will consist of:

- A nominal 150 MW gas-fueled General Electric 7241 FA CTG;
- A supplementary-fired HRSG with natural gas fueled duct burners (DB);
- A nominal 150 MW STG;
- A nominal 160-foot stack;
- An emergency diesel engine fire pump and small ultralow sulfur diesel (ULSD) fuel oil (FO)storage tank;
- A nominal 750 kilowatts (kW) safe shutdown diesel generator with a ULSD FO storage tank; and
- A mechanical draft cooling tower with drift eliminators.

EMISSIONS UNITS

This permit authorizes construction and installation of the following new emissions units:

EU ID NO.	EMISSION UNIT DESCRIPTION
009	Unit 4 is comprised of: a nominal 150 MW natural gas-fueled General Electric 7FA CTG equipped with evaporative inlet air cooling equipment; a supplementary-fired HRSG with a nominal 600 million Btu per hour (mmBtu) DB; a HRSG stack; and a nominal 150 MW STG.
010	Emergency fire pump diesel engine and ULSD fuel oil storage tank.
011	Diesel electric generator for safe shutdown of Unit 4 and ULSD FO storage tank.
012	An eight-cell mechanical cooling tower with individual exhaust fans and drift eliminators.

REGULATORY CLASSIFICATION

The facility is a major Prevention of Significant Deterioration (PSD) stationary source in accordance with Rule 62-212.400, F.A.C. Unit 4 is subject to the PSD rules including a determination of best available control technology (BACT).

The facility is a Title V major source of air pollution in accordance with Chapter 213, Florida Administrative Code (F.A.C.).

The facility operates existing units subject to the Acid Rain provisions of Title IV of the Clean Air Act (CAA).

The facility operates units subject to the Standards of Performance for New Stationary Sources (NSPS) pursuant to 40 CFR Part 60. Unit 4 is subject to 40 CFR 60, Subpart KKKK – NSPS for Stationary Combustion Turbines that Commence Construction after February 18, 2005. This rule also covers DB burners that are incorporated into combined cycle projects. The emergency fire pump diesel engine and the safe shutdown diesel generator are subject to 40 CFR 60, Subpart IIII – NSPS for Stationary Compression Ignition Internal Combustion Engines.

The existing facility is a major source of hazardous air pollutants (HAP). Unit 4 is potentially subject to 40 CFR 63, Subpart YYYY - National Emission Standards for Hazardous Air Pollutants (NESHAP) for Stationary Combustion Turbines. The applicability of this rule has been stayed for lean premix and diffusion flame gas-fired combustion turbines such as planned for this project. The safe shutdown diesel generator is subject only to the initial notification requirements of 40 CFR 60, Subpart ZZZZ – NESHAP for Stationary Reciprocating Internal Combustion Engines.

The facility is subject to the Federal Clean Air Interstate Rule (CAIR) in accordance with the Department's final rule at Section 62-296.470, F.A.C.

The facility operates units that were certified under the Florida Power Plant Siting Act (FPPSA), 403.501-518, F.S. (Unit 4 is also subject to the requirements of the FPPSA).

RELEVANT DOCUMENTS

The following relevant documents are not a part of this permit, but helped form the basis for this permitting action: the permit application and additional information received to make it complete; the draft air construction permit; and the Department's Technical Evaluation and Preliminary Determination.

SECTION II. ADMINISTRATIVE REQUIREMENTS

1. Permitting Authority: The Permitting Authority for this project is the Bureau of Air Regulation in the Division of Air Resource Management of the Department. The mailing address for the Bureau of Air Regulation is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400.

2. Compliance Authority: All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Central District Office. The mailing address and phone number of the Central District Office are: Department of Environmental Protection, Central District Office, 3319 Maguire Boulevard, Suite 232, Orlando Florida 32803-3767. Telephone: (407)894-7555. Fax: (407)897-5963.

3. Appendices: The following Appendices are attached as part of this permit: Appendices A, BD, GC (General Conditions), IIII, KKKK, SC, XS, YYYY and ZZZZ.

4. Applicable Regulations, Forms and Application Procedures: Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of: Chapter 403, F.S.; and Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297, F.A.C. Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.

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

6. Modifications: No emissions unit shall be constructed or modified without obtaining an air construction permit from the Department. Such a permit shall be obtained prior to beginning construction or modification. [Rules 62-210.300(1) and 62-212.300(1)(a), F.A.C.]

7. Construction and Expiration: The permit expiration date includes sufficient time to complete construction, perform required testing, submit test reports, and submit an application for a Title V operation permit to the Department. Approval to construct shall become invalid for any of the following reasons: construction is not commenced within 18 months after issuance of this permit; construction is discontinued for a period of 18 months or more; or construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. In conjunction with an extension of the 18-month period to commence or continue construction (or to construct the project in phases), the Department may require the permittee to demonstrate the adequacy of any previous determination of BACT for emissions units regulated by the project. For good cause, the permittee may request that this PSD air construction permit be extended. Such a request shall be submitted to the Department's Bureau of Air Regulation at least sixty (60) days prior to the expiration of this permit.
[Rules 62-4.070(4), 62-4.080, 62-210.300(1), and 62-212.400(6)(b), F.A.C.]

8. Title V Permit: This permit authorizes specific modifications and/or new construction on the affected emissions units as well as initial operation to determine compliance with conditions of this permit. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit at least 90 days prior to expiration of this permit, but no later than 180 days after completing the required work and commencing operation. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Bureau of Air Regulation with copies to the Compliance Authority.
[Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

SECTION III - EMISSIONS UNITS SPECIFIC CONDITIONS

A. Combined Cycle Unit 4 (EU 009)

This section of the permit addresses the following emissions unit.

EU ID NO.	EMISSION UNIT DESCRIPTION
009	Unit 4 is comprised of: a nominal 150 MW natural gas-fueled General Electric 7FA CTG equipped with evaporative inlet air cooling equipment; a supplementary-fired HRSG with a nominal 600 mmBtu/hr DB; a HRSG stack; and a nominal 150 MW STG.

Applicable Standards and Regulations

1. BACT Determinations: The emission unit addressed in this section is subject to a BACT determination for carbon monoxide (CO), nitrogen oxides (NO_X), particulate matter (PM/PM_{10}), sulfuric acid mist (SAM), and sulfur dioxide (SO_2). [Rule 62-212.400, F.A.C.]

2. NSPS Requirements: The combustion turbine shall comply with all applicable requirements of 40 CFR 60, listed below, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Department determines that compliance with the BACT emissions performance requirements also assures compliance with the NSPS for Subpart KKKK. Some separate reporting and monitoring may be required by these subparts.

   (a) Subpart A, General Provisions, including:

   - 40 CFR 60.7, Notification and Record Keeping
   - 40 CFR 60.8, Performance Tests
   - 40 CFR 60.11, Compliance with Standards and Maintenance Requirements
   - 40 CFR 60.12, Circumvention
   - 40 CFR 60.13, Monitoring Requirements
   - 40 CFR 60.19, General Notification and Reporting Requirements

   (b) Subpart KKKK, Standards of Performance for Stationary Gas Turbines: These provisions include standards for combustion gas turbines and duct burners.

Equipment

3. CTG: The permittee is authorized to install, tune, operate, and maintain one natural gas-fueled GE Model 7FA CTG with a nominal generating capacity of 150 MW. The CTG will be equipped with Dry Low NO_x (DLN) combustors and an inlet air filtration system with evaporative coolers. The unit shall be equipped with the Speedtronic™ Mark VI (or more recent version) automated gas turbine control system. [Application and Design]

4. HRSG: The permittee is authorized to install, operate, and maintain one HRSG with a HRSG exhaust stack. The HRSG shall be designed to recover heat energy from the gas turbine and deliver steam to the steam turbine electrical generator with a nominal generating capacity of 150 MW. The HRSG will be equipped with a supplemental gas-fired DB having a nominal heat input rate of 600 mmBtu (High Heating Value or HHV). [Application]

Control Technology

5. DLN Combustion: The permittee shall operate and maintain the GE DLN 2.6 combustion system (or more recent upgrade) to control NO_X emissions from the CTG. Prior to the initial emissions performance tests required for the gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the permitted levels for CO and sufficiently low NO_X values to meet the NO_X limits with the additional SCR control technology described below. Thereafter, the system shall be maintained and tuned in accordance with the manufacturer's recommendations.

6. Selective Catalytic Reduction (SCR) System: The permittee shall install, tune, operate, and maintain an SCR system to control NO_X emissions from the CTG and DB. The SCR system consists of an ammonia (NH_3) injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NO_X and NH_3 emissions. In accordance with 40 CFR 68.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions in 40 CFR 68. [Design and Rule 62-212.400(BACT), F.A.C.]

PERFORMANCE RESTRICTIONS

7. Capacity – CTG: The nominal heat input rating of the CTG is 1,860 mmBtu per hour based on a compressor inlet air temperature of 59 °F, International Organization for Standardization (ISO) conditions, the HHV of natural gas and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.
[Rule 62-210.200(Definitions – Potential to Emit), F.A.C.]

8. Capacity - DB: The nominal heat input rating of the DB located within the HRSG is 600 mmBtu per hour based on the HHV of natural gas. Only natural gas shall be fired in the DB.
[Rule 62-210.200(Definitions – Potential to Emit), F.A.C.]

9. Hours of Operation: The CTG and the DB may operate throughout the year (8760 hours per year).
[Rules 62-210.200(Definitions - PTE) and 62-212.400 (BACT), F.A.C.]

10. Authorized Fuel: The CTG turbine shall fire only natural gas, which shall contain no more than 2 grains (gr) of sulfur per 100 standard cubic feet (SCF) of natural gas.
[Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

11. Methods of Operation: Subject to the restrictions and requirements of this permit, the gas turbine may operate under the following methods of operation.
    a. *Combined Cycle Operation*: The CTG/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.
    b. *Pseudo Simple Cycle Operation*: The CTG/HRSG system may operate in a pseudo simple cycle mode whereby steam from the HRSG bypasses the steam turbine-electrical generator and is dumped directly to the condenser. The same emission limits apply as when operating in combined cycle mode.
    c. *Evaporative Cooling*: Evaporative cooling is the injection of fine water droplets into the gas turbine compressor inlet air, which reduces the gas temperature through evaporative cooling. Lower compressor inlet temperatures result in a more mass flow rate through the gas turbine with a boost in electrical power production. The emissions performance remains within the normal profile of the gas turbine for the lower compressor inlet temperatures. Evaporative cooling will be implemented at ambient temperatures of 60 °F or higher.
    d. *DB Firing*: The HRSG system may fire natural gas in the DB to provide additional steam-generated electrical power.

    [Application and Rules 62-210.200 (PTE) and 62-212.400 (BACT), F.A.C.]

A. Combined Cycle Unit 4 (EU 009)

Emissions Standards

12. Emission Standards: Emissions from the CTG/HRSG system shall not exceed the following standards.

Pollutant	Method of Operation	Initial and Annual Stack Test 3-Run Average		CEMS Average
		ppmvd @15% O_2	lb/hr [f]	ppmvd @ 15% O_2
CO [a]	CTG Normal	4.1	16.7	8.0, 24-hr block
	CTG & DB	7.6	40.8	
	All Modes	NA	NA	6.0, 12-month rolling
NO_X [b]	CTG Normal	2.0	13.4	2.0, 24-hr and 15, 30 days rolling[g]
	CTG & DB	2.0	17.6	
PM/PM_{10} [c]	All Modes	2 gr S/100 SCF of gas		
		Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	All Modes	2 gr S/100 SCF of gas		
Ammonia [e]	CTG, All Modes	5.0	NA	NA

a. Continuous compliance with the 24-hour CO standards shall be demonstrated based on data collected by the required continuous emissions monitoring system (CEMS). The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for normal natural gas and the duct burner mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for normal natural gas and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as nitrogen dioxide (NO_2).

c. The sulfur fuel specification combined with the efficient combustion design and operation of the gas turbine represents BACT for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specification effectively limits the potential emissions of SAM and SO_2 from the gas turbines and represents BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur or by fuel supplier/vendor reports as detailed in the draft permit.

e. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

f. The mass emission rate standards are based on a turbine inlet condition of 59 °F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

g. Compliance with the 40 CFR 60, NSPS, Subpart KKKK as described in 60.4380(b)(1).

[Rule 62-212.400 (BACT), F.A.C.]

Excess Emissions

{Permitting Note: The following conditions apply only to the SIP-based emissions standards specified in Condition No. 12 of this section. Rule 62-210.700, F.A.C. (Excess Emissions) cannot vary or supersede any federal provision of the NSPS, or Acid Rain programs.}

13. Operating Procedures: BACT determinations established by this permit rely on "good operating practices" to reduce emissions. Therefore, all operators and supervisors shall be properly trained to operate and ensure maintenance of the CTG, DB, HRSG, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods for minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

14. Definitions:

    a. *Startup* is defined as the commencement of operation of any emissions unit which has shut down or ceased operation for a period of time sufficient to cause temperature, pressure, chemical or pollution control device imbalances, which result in excess emissions. [Rule 62-210.200(245), F.A.C.]

    b. *Shutdown* is the cessation of the operation of an emissions unit for any purpose. [Rule 62-210.200(230), F.A.C.]

    c. *Malfunction* is defined as any unavoidable mechanical and/or electrical failure of air pollution control equipment or process equipment or of a process resulting in operation in an abnormal or unusual manner. [Rule 62-210.200(159), F.A.C.]

15. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

16. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

17. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, and documented malfunctions shall be permitted, provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. For the CTG/HRSG system, excess emissions of NO_X and CO emissions resulting from startup, shutdown, or documented malfunctions shall not exceed the following specified time periods in any 24-hour period (for the purposes of this condition, "any 24-hour period" means a calendar day, midnight to midnight).

    a. *STG/HRSG System Cold Startup:* For cold startup of the STG/HRSG system, excess NO_X and CO emissions from the CTG/HRSG system shall not exceed six hours in any 24-hour period. A "cold startup of the STG/HRSG system" is defined as startup of the combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

    {Permitting Note: During a cold startup of the steam turbine system, the CTG/HRSG system is brought on line at low load to gradually increase the temperature of the STG and prevent thermal metal fatigue.}

    b. *STG/HRSG System Warm Startup:* For warm startup of the STG/HRSG system, excess NO_X and CO emissions shall not exceed four hours in any 24-hour period. A "warm startup of the STG/HRSG system" is defined as a startup of the combined cycle system following a shutdown of the steam turbine lasting at least 8 hours and less than 48 hours.

c. *STG/HRSG System Hot Startup*: For hot startup of the STG/HRSG system, excess NO_X and CO emissions shall not exceed two hours in any 24-hour period. A "hot startup of the STG/HRSG system" is defined as a startup of the combined cycle system following a shutdown of the steam turbine lasting less than 8 hours.

d. *Shutdown:* For shutdown of the combined cycle operation, excess NO_X and CO emissions from the CTG/HRSG system shall not exceed three hours in any 24-hour period.

e. *Documented Malfunction:* For the CTG/HSRG system, excess emissions of NO_X and CO resulting from documented malfunctions shall not exceed two hours in any 24-hour period. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Compliance Authority by telephone, facsimile transmittal, or electronic mail.

18. Ammonia Injection: Ammonia injection shall begin as soon as operation of the CTG/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above condition allows excess emissions only for specifically defined periods of startup, shutdown, fuel switching, and documented malfunction of the CTG/HRSG system including the pollution control equipment. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

19. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Compliance Authority with an advance notice of at least 14 days that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

Emissions Performance Testing

20. Test Methods: Required tests shall be performed in accordance with the following reference methods.

Method	Description of Method and Comments
CTM-027 or 320	Procedure for Collection and Analysis of Ammonia in Stationary Source. {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.} Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines

No other methods may be used for compliance testing unless prior written approval is received from the administrator of the Department's Emissions Monitoring Section in accordance with an alternate sampling procedure pursuant to 62-297.620, F.A.C.
[Rules 62-204.800 and 62-297.100, F.A.C.; 40 CFR 60, Appendix A]

21. Initial Compliance Determinations: The CTG shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after the initial startup. The unit shall be tested when firing natural gas and when using the duct burners. For each run during tests for visible emissions and ammonia slip, emissions of CO and NO_X recorded by the CEMS shall also be reported. NO_X and CO emissions data collected during the required continuous monitor Relative Accuracy Test Audits (RATAs) may be used to demonstrate initial compliance with the CO and NO_x standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may be used to demonstrate compliance with the CO and NO_X mass rate emissions standards. The Department may, for good reason, require the permittee to conduct additional tests after major replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc.
[Rule 62-297.310(7)(a) and (b), F.A.C. and 40 CFR 60.8]

22. Annual Compliance Tests: During each federal fiscal year (October 1st, to September 30th), the CTG shall be tested to demonstrate compliance with the emission standard for visible emissions. NO_X and CO emissions data collected during the required continuous monitor RATA may be used to demonstrate compliance with the CO and NO_x standards. NO_X emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4, F.A.C.]

23. Continuous Compliance: The permittee shall demonstrate continuous compliance with the 24-hour block and 12-month rolling average CO emissions standards and with the 24-hour block and 30 unit operating day rolling average NO_X emission standards based on data collected by the certified CEMS for each pollutant. Within 45 days of conducting any RATA on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter. [Rule 62-212.400 (BACT), F.A.C.]

24. Compliance for SAM, SO_2 and PM/PM_{10}: In stack compliance testing is not required for SAM, SO_2 and PM/PM_{10}. Compliance with the limits and control requirements for SAM, SO_2 and PM/PM_{10} is based on the recordkeeping required in Specific Condition 30, visible emissions testing and CO continuous monitoring. [Rule 62-212.400 (BACT), F.A.C.]

Continuous Monitoring Requirements

25. CEMS: The permittee shall install, calibrate, maintain, and operate CEMS to measure and record the emissions of CO and NO_X from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NO_X standard (and subject to the specified averaging period), the permittee shall notify the Compliance Authority.

    a. *CO Monitor:* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A within 60 calendar days of achieving permitted capacity as defined in Rule 62-297.310(2), F.A.C., but no later than 180 calendar days after initial startup. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Compliance Authority. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately, considering the allowable methods of operation and corresponding emission standards.

b. *NO_X Monitor:* The NO_X monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60.

c. *Diluent Monitor:* The oxygen (O_2) or carbon dioxide (CO_2) content of the flue gas shall be monitored at the location where CO and NO_X are monitored to correct the measured emissions rates to 15% oxygen. If a CO_2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

26. CEMS Data Requirements:

a. *Data Collection*: Emissions shall be monitored and recorded at all times including startup, operation, shutdown, and malfunction except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NO_X as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emissions rates shall be corrected to ISO conditions.

b. *Valid Hour*: Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values.

c. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of all available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, the missing data substitution methodology of 40 CFR Part 75, Subpart D, shall not be utilized. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

{Permitting Note: There may be more than one 24-hour compliance demonstration required for CO and NO_X emissions depending on the use of alternate methods of operation.}

d. *12-month Rolling Averages:* Compliance with the long-term emission limit for CO shall be based on a 12-month rolling average. Each 12-month rolling average shall be the arithmetic average of all valid hourly averages collected during the current calendar month and the previous 11 calendar months.

e. *30 unit operating day Rolling Average:* Compliance with this rolling average is as described in 40 CFR 60.4380(b)(1).

f. *Data Exclusion:* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction and DLN tuning. Some of the CEMS emissions data recorded during these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 15 and 17 of this section. All periods of data excluded shall be consecutive for each such episode and only data obtained during the described episodes (startup, shutdown, malfunction, DLN tuning) may be used for the appropriate exclusion periods. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

g. *Availability*: Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this permit, except as otherwise authorized by the Department's Compliance Authority.

[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

27. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system prior to the initial compliance tests. The permittee shall document and periodically update the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load condition.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

Records and Reports

28. Monitoring of Capacity: The permittee shall monitor and record the operating rate of the CTG and HRSG DB system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of the natural gas in accordance with the provisions of 40 CFR 75, Appendix D.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

29. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for the natural gas fuel in a written or electronic log for the gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75, Appendix D.
[Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

30. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this permit by maintaining the reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D4468-85, D5504-01, D6228-98 and D6667-01, D3246-81 or more recent versions. These methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D.
[Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

31. Emissions Performance Test Reports: A report indicating the results of any required emissions performance test shall be submitted to the Compliance Authority no later than 45 days after completion of the last test run. The test report shall provide sufficient detail on the tested emission unit and the procedures used to allow the Department to determine if the test was properly conducted and if the test results were properly computed. At a minimum, the test report shall provide the applicable information listed in Rule 62-297.310(8)(c), F.A.C. and in Appendix SC of this permit.
[Rule 62-297.310(8), F.A.C.]

32. Excess Emissions Reporting:

    a. *Malfunction Notification:* If emissions in excess of a standard (subject to the specified averaging period) occur due to malfunction, the permittee shall notify the Compliance Authority within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

    b. *SIP Quarterly Permit Limits Excess Emissions Report:* Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Compliance Authority summarizing periods of CO and NO_X emissions in excess of the BACT permit standards following the NSPS format in 40 CFR 60.7(c), Subpart A. Periods of startup, shutdown and malfunction, shall be monitored, recorded and reported as excess emissions when emission levels exceed the standards specified in this permit. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

    c. *NSPS Semi-Annual Excess Emissions Reports*: Within thirty (30) days following each calendar semi-annual period, the permittee shall submit a report on any periods of excess emissions that occurred during the previous semi-annual period to the Compliance Authority.

    {Note: If there are no periods of excess emissions as defined in NSPS Subpart KKKK, a statement to that effect may be submitted with the SIP Quarterly Report to suffice for the NSPS Semi-Annual Report.}

    [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; 40 CFR 60.7, and 60.332(j)(1)]

33. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating hours and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority as required by Rule 62-210.370(2), F.A.C.

SECTION III - EMISSIONS UNITS SPECIFIC CONDITIONS

B. Emergency Diesel Fire Pump Engine

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
010	Emergency fire pump diesel engine and ULSD FO storage tank.

NSPS APPLICABILITY

1. NSPS Subpart IIII Applicability: The emergency fire pump diesel engine is an Emergency Stationary Compression Ignition Internal Combustion Engine (ICE) and is subject to 40 CFR 60, Subpart IIII. It shall comply with 40 CFR 60, Subpart IIII only to the extent that the regulations apply to the emissions unit and its operations (e.g. fire pumps, horsepower, and model year selected).
   [40 CFR 60, Subpart IIII – NSPS Stationary Compression Ignition ICE]

EQUIPMENT SPECIFICATIONS

2. Equipment: The permittee is authorized to install, operate, and maintain one model year 2009 (or later) fire pump diesel engine with a rating less than 300 horsepower (hp) and an associated nominal 500 gallon ULSD FO storage tank.

EMISSIONS AND PERFORMANCE REQUIREMENTS

3. Hours of Operation: The fire pump may operate in response to emergency conditions and 80 non-emergency hours per year for maintenance testing.
   [Applicant Request and Rule 62-210.200 (PTE), F.A.C.]

4. Authorized Fuel: This unit shall fire ULSD FO (or superior fuel), which shall contain no more than 0.0015% sulfur by weight. The permittee shall maintain a file of the certified fuel sulfur analyses from the fuel vendor containing the most recent 5 years of records.
   [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

5. Fire Pump Diesel Engine BACT Emission Limits in grams per brake horsepower-hour (gm/bhp-hr):

Size (hp)	Model Year	CO	SO_2	NMHC*+NO_X	PM
175 ≤ hp < 300	≥ 2009	2.6	ULSD FO	3.0	0.15

   * Non-Methane Hydrocarbons (NMHC) are surrogate for VOC.

   {The NMHC+NO_X and PM BACT limits are equal to the values corresponding to the size class indicated above and cited in 40 CFR 60, Subpart IIII.}

6. Compliance, Testing and Certification Requirements: The permittee shall adhere to the compliance testing and certification requirements listed in 40 CFR 60.4211 and maintain records demonstrating use of ULSD FO.
   [Rule 62-212.400 (BACT), F.A.C. and 40 CFR 60.4211]

SECTION III - EMISSIONS UNITS SPECIFIC CONDITIONS

C. Safe Shutdown Diesel Electric Generator

This section of the permit addresses the following emissions unit.

ID	Emission Unit Description
011	Diesel electric generator for safe shutdown of Unit 4 and ULSD FO storage tank.

NESHAPS APPLICABILITY

1. NESHAP Subpart ZZZZ Applicability: The safe shutdown generator is a Liquid Fueled Reciprocating Internal Combustion Engine (RICE) subject to 40 CFR 63, Subpart ZZZZ. The safe shutdown diesel generator is an emergency generator and is subject only to the initial notification requirements of Subpart ZZZZ.
   [40 CFR 63, Subpart ZZZZ – NESHAP for RICE and Rule 62-204.800(11)(b)80, F.A.C.]

NSPS APPLICABILITY

2. NSPS Subpart IIII Applicability: The safe shutdown generator is a Stationary Compression Ignition Internal Combustion Engines (Stationary ICE) and is subject to 40 CFR 60, Subpart IIII.
   [40 CFR 60, Subpart IIII – NSPS for Stationary ICE]

EQUIPMENT SPECIFICATIONS

3. Equipment: The permittee is authorized to install, operate, and maintain a nominal 750 kW diesel electric generator and an associated nominal 1000 gallon ULSD FO storage tank.
   [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

EMISSIONS AND PERFORMANCE REQUIREMENTS

4. Hours of Operation: The safe shutdown generator may operate as needed with 200 non-emergency hours per year for maintenance testing. [Applicant Request and Rule 62-210.200(PTE), F.A.C.]

5. Authorized Fuel: This unit shall fire ULSD FO (or superior fuel), which shall contain no more than 0.0015% sulfur by weight. The permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. [Rules 62-210.200(PTE) and 62-212.400 (BACT), F.A.C.]

6. Safe Shutdown Generator BACT Emissions Limits in gm/bhp-hr and (gm/kW-hr):

Size (kW)	Model Year	CO	SO_2	NMHC+NO_X	PM
560 < kW ≤ 2237	≥ 2006	2.6 (3.5)	ULSD FO	4.8 (6.4)*	0.15 (0.20)

* Non-Methane Hydrocarbons (NMHC) are surrogate for VOC.

{The NMHC+NO_X and PM BACT limits are equal to the values corresponding to the size class indicated above and cited in 40 CFR 60, Subpart IIII.}

7. Compliance, Testing and Certification Requirements: The permittee shall adhere to the compliance testing and certification requirements listed in 40 CFR 60.4211 and maintain records demonstrating use of ULSD FO. [Rule 62-212.400 (BACT), F.A.C. and 40 CFR 60.4211]

SECTION III - EMISSIONS UNITS SPECIFIC CONDITIONS

D. Unit 4 Cooling Tower (EU 012)

This section of the permit addresses the following new emissions unit.

ID	Emission Unit Description
012	Unit 4 Cooling Tower – consisting of eight cells with eight individual exhaust fans

Equipment

1. Cooling Tower: The permittee is authorized to install one 8-cell linear mechanical draft cooling tower with the following nominal design characteristics: an air volumetric flow rate of 1,004,800 actual cubic feet per minute per cell; cell height of 56 feet; cell diameter of 30 feet; and drift eliminators with a drift rate of no more than 0.0005 percent of the circulating water flow. [Application and Design]

Emissions and Performance Requirements

2. Drift Rate: Within 60 days of commencing commercial operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of no more than 0.0005 percent of the circulating water flow rate. [Rule 62-212.400(BACT), F.A.C.]

   {Permitting Note: This work practice standard is established as BACT for PM/PM_{10} emissions from the cooling tower. Based on this design criteria, potential emissions are expected to be less than 3 tons of PM/PM_{10} per year.}

SECTION IV. APPENDICES

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SECTION IV. APPENDIX A

NSPS SUBPART A AND NESHAP SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

NSPS - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a New Source Performance Standard of 40 CFR 60 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 60.1 Applicability.

§ 60.2 Definitions.

§ 60.3 Units and abbreviations.

§ 60.4 Address.

§ 60.5 Determination of construction or modification.

§ 60.6 Review of plans.

§ 60.7 Notification and Record Keeping.

§ 60.8 Performance Tests.

§ 60.9 Availability of information.

§ 60.10 State Authority.

§ 60.11 Compliance with Standards and Maintenance Requirements.

§ 60.12 Circumvention.

§ 60.13 Monitoring Requirements.

§ 60.14 Modification.

§ 60.15 Reconstruction.

§ 60.16 Priority List.

§ 60.17 Incorporations by Reference.

§ 60.18 General Control Device Requirements.

§ 60.19 General Notification and Reporting Requirements.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

NESHAP - SUBPART A, IDENTIFICATION OF GENERAL PROVISIONS

The provisions of this Subpart may be provided in full upon request. Emissions units subject to a National Emission Standards for Hazardous Air Pollutants of 40 CFR 63 are also subject to the applicable requirements of Subpart A, the General Provisions, including:

§ 63.1 Applicability.

§ 63.2 Definitions.

§ 63.3 Units and abbreviations.

§ 63.4 Prohibited Activities and Circumvention.

§ 63.5 Preconstruction Review and Notification Requirements.

§ 63.6 Compliance with Standards and Maintenance Requirements.

§ 63.7 Performance Testing Requirements.

§ 63.8 Monitoring Requirements.

§ 63.9 Notification Requirements.

§ 63.10 Recordkeeping and Reporting Requirements.

§ 63.11 Control Device Requirements.

§ 63.12 State Authority and Delegations.

§ 63.13 Addresses of State Air Pollution Control Agencies and EPA Regional Offices.

§ 63.14 Incorporation by Reference.

§ 63.15 Availability of Information and Confidentiality.

Individual subparts may exempt specific equipment or processes from some or all of these requirements. The general provisions may be provided in full upon request.

SECTION IV. APPENDIX BD

BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Refer to the BACT proposal discussed in the initial Technical Evaluation for this project and to the Final Determination issued with the Final permit for the rationale regarding the following BACT determination.

Pollutant	Method of Operation	Initial and Annual Stack Test 3-Run Average		CEMS Average
		ppmvd @15% O_2	lb/hr [f]	ppmvd @ 15% O_2
CO [a]	CTG Normal	4.1	16.7	8.0, 24-hr block
	CTG & DB	7.6	40.8	
	All Modes	NA	NA	6.0, 12-month rolling
NO_X [b]	CTG Normal	2.0	13.4	2.0, 24-hr and 15, 30-day rolling [g]
	CTG & DB	2.0	17.6	
PM/PM_{10} [c]	All Modes	2 gr S/100 SCF of gas Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2 [d]	All Modes	2 gr S/100 SCF of gas		
Ammonia [e]	CTG, All Modes	5.0	NA	NA

a. Continuous compliance with the 24-hour CO standards shall be demonstrated based on data collected by the required continuous emissions monitoring system (CEMS). The initial and annual EPA Method 10 tests associated with the certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for normal natural gas and the duct burner mode.

b. Continuous compliance with the 24-hr NO_X standards shall be demonstrated based on data collected by the required CEMS. The initial and annual EPA Method 7E or Method 20 tests associated with demonstration of compliance with 40 CFR 60, Subpart KKKK or certification of the CEMS instruments shall also be used to demonstrate compliance with the individual standards for normal natural gas and duct burner modes during the time of those tests. NO_X mass emission rates are defined as oxides of nitrogen expressed as nitrogen dioxide (NO_2).

c. The sulfur fuel specification combined with the efficient combustion design and operation of the gas turbine represents BACT for PM/PM_{10} emissions. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specification effectively limits the potential emissions of SAM and SO_2 from the gas turbines and represents BACT for these pollutants. Compliance with the fuel sulfur specifications shall be determined by the ASTM methods for determination of fuel sulfur or by fuel supplier/vendor reports as detailed in the draft permit.

e. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTM-027 or EPA Method 320.

f. The mass emission rate standards are based on a turbine inlet condition of 59 °F, evaporative cooling on, and using the HHV of the fuel. Mass emission rate may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.

g. Compliance with the 40 CFR 60, NSPS, Subpart KKKK as described in 60.4380(b)(1).

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:

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

   Reasonable time may depend on the nature of the concern being investigated.
8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:

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

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

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

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

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

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

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

13. This permit also constitutes:

    a. Determination of Best Available Control Technology (X);
    b. Determination of Prevention of Significant Deterioration (X);
    c. Compliance with National Emission Standards for Hazardous Air Pollutants (X); and
    d. Compliance with New Source Performance Standards (X).

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

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

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

SECTION IV. APPENDIX IIII

NSPS REQUIREMENTS FOR STATIONARY COMPRESSION IGNITION INTERNAL COMBUSTION ENGINES

The emergency fire pump diesel engine and the safe shutdown generator are regulated for purposes of the Air Resource Management System (ARMS) as Emissions Unit Nos. 010 and 011. They are subject to the applicable requirements of 40 CFR 60, Subpart IIII--Standards of Performance for Stationary Compression Ignition Internal Combustion Engines. The provisions of this Subpart may be provided in full upon request and are also available beginning at Section 60.4200 at:

www.access.gpo.gov/nara/cfr/waisidx_07/40cfr60_07.html .

NSPS SUBPART KKKK REQUIREMENTS FOR GAS TURBINES

CIPP Unit 4 is regulated as Emissions Unit 009. The gas turbine and the HRSG duct burner are part of the combined cycle unit. This emissions unit shall comply with all applicable requirements of 40 CFR 60, Subpart KKKK-- Standards of Performance for Stationary Combustion Turbines as existed in the 2007 version, in effect at the time of the permit issuance.

The full provisions may be provided in full upon request and are also available beginning at Section 60.4300 at:

www.access.gpo.gov/nara/cfr/waisidx_07/40cfr60_07.html .

Table 1 is a listing of the NO_X limits from Subpart KKKK that apply to the CIPP Unit 4 project.

Table 1 to Subpart KKKK of Part 60. NO_X Emission Limits for New Stationary Combustion Turbines*

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_X emission standard
New, modified, or reconstructed turbine firing natural gas	> 850 mmBtu/h	15 ppm at 15 percent O_2 or 54 ng/J of useful output (0.43 lb/MWh).

* Only the portion of the table that includes the NO_X Requirements applicable to the CIPP Unit 4.

SECTION IV. APPENDIX SC

STANDARD CONDITIONS

Unless otherwise specified in the permit, the following conditions apply to all emissions units and activities at this facility.

EMISSIONS AND CONTROLS

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

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

3. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for longer duration. [Rule 62-210.700(1), F.A.C.]

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

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

6. VOC or OS Emissions: No person shall store, pump, handle, process, load, unload or use in any process or installation, volatile organic compounds or organic solvents without applying known and existing vapor emission control devices or systems deemed necessary and ordered by the Department. [Rule 62-296.320(1), F.A.C.]

7. Objectionable Odor Prohibited: No person shall cause, suffer, allow or permit the discharge of air pollutants, which cause or contribute to an objectionable odor. An "objectionable odor" means any odor present in the outdoor atmosphere which by itself or in combination with other odors, is or may be harmful or injurious to human health or welfare, which unreasonably interferes with the comfortable use and enjoyment of life or property, or which creates a nuisance. [Rules 62-296.320(2) and62-210.200(203), F.A.C.]

8. General Visible Emissions: No person shall cause, let, permit, suffer or allow to be discharged into the atmosphere the emissions of air pollutants from any activity equal to or greater than 20 percent opacity. [Rule 62-296.320(4)(b)1, F.A.C.]

9. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

TESTING REQUIREMENTS

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

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

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

13. Test Procedures: Tests shall be conducted in accordance with all applicable requirements of Chapter 62-297, F.A.C.

    a. Required Sampling Time. Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes. The minimum observation period for a visible emissions compliance test shall be thirty (30) minutes. The observation period shall include the period during which the highest opacity can reasonably be expected to occur.

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

    c. Calibration of Sampling Equipment. Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1, F.A.C.

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

14. Determination of Process Variables

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

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

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

15. Sampling Facilities: The permittee shall install permanent stack sampling ports and provide sampling facilities that meet the requirements of Rule 62-297.310(6), F.A.C.

16. Test Notification: The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator. [Rule 62-297.310(7)(a)9, F.A.C.]

17. Special Compliance Tests: When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department. [Rule 62-297.310(7)(b), F.A.C.]

18. Test Reports: The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to

determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

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

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

RECORDS AND REPORTS

19. Records Retention: All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2, F.A.C.]

20. Annual Operating Report: The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(2), F.A.C.]

SECTION IV. APPENDIX XS

SEMIANNUAL NSPS EXCESS EMISSIONS REPORT

FIGURE 1. SUMMARY REPORT - GASEOUS AND OPACITY EXCESS EMISSION AND MONITORING SYSTEM PERFORMANCE

[Note: This form is referenced in 40 CFR 60.7, Subpart A-General Provisions]

Pollutant *(Circle One)*: SO_2 NO_X TRS H_2S CO Opacity

Reporting period dates: From _____ to _____

Company: _____

Emission Limitation: _____

Address: _____

Monitor Manufacturer: _____

Model No.: _____

Date of Latest CMS Certification or Audit: _____

Process Unit(s) Description: _____

Total source operating time in reporting period [1]: _____

Emission data summary [1]	**CMS performance summary** [1]
1. Duration of excess emissions in reporting period due to:	1. CMS downtime in reporting period due to:
a. Startup/shutdown ..... ____	a. Monitor equipment malfunctions ..... ____
b. Control equipment problems ..... ____	b. Non-Monitor equipment malfunctions ..... ____
c. Process problems ..... ____	c. Quality assurance calibration ..... ____
d. Other known causes ..... ____	d. Other known causes ..... ____
e. Unknown causes ..... ____	e. Unknown causes ..... ____
2. Total duration of excess emissions ..... ____	2. Total CMS Downtime ..... ____
3. Total duration of excess emissions x (100) / [Total source operating time] ..... ____ %[2]	3. [Total CMS Downtime] x (100) / [Total source operating time] ..... ____ %[2]

[1] For opacity, record all times in minutes. For gases, record all times in hours.

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

Note: On a separate page, describe any changes since the last in CMS, process or controls.

I certify that the information contained in this report is true, accurate, and complete.

Name: _____

Signature: _____ *Date*: _____

Title: _____

The Cane Island Power Park Unit 4 combustion turbine is subject to the applicable requirements of 40 CFR 63, Subpart YYYY--National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines. The provisions of this Subpart may be provided in full upon request and are also available beginning at Section 63.6080 at:

www.access.gpo.gov/nara/cfr/waisidx_07/40cfr63c_07.html .

Following is important information related to the present status of the mentioned subpart.

Staying of the Rule

On August 18, 2004, EPA stayed the effectiveness of 40 CFR 63, Subpart YYYY for lean premix gas turbines such as the one proposed for the Unit 4 Project. Following is the change in 40 CFR 63 that stays effectiveness:

§ 63.6095(d) Stay of standards for gas-fired subcategories.

If you start up a new or reconstructed stationary combustion turbine that is a lean premix gas-fired stationary combustion turbine or diffusion flame gas-fired stationary combustion turbine as defined by this subpart, you must comply with the Initial Notification requirements set forth in Sec. 63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance and publishes a document in the Federal Register.

Requirements

The applicable requirements in Subpart YYYY are:

§ 63.6145 What notifications must I submit and when?

(a) You must submit all of the notifications in §§ 63.7(b) and (c), 63.8(e), 63.8(f)(4), and 63.9(b) and (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you start up your new or reconstructed stationary combustion turbine before March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after March 5, 2004.

(c) As specified in § 63.9(b), if you start up your new or reconstructed stationary combustion turbine on or after March 5, 2004, you must submit an Initial Notification not later than 120 calendar days after you become subject to this subpart.

(d) If you are required to submit an Initial Notification but are otherwise not affected by the emission limitation requirements of this subpart, in accordance with § 63.6090(b), your notification must include the information in § 63.9(b)(2)(i) through (v) and a statement that your new or reconstructed stationary combustion turbine has no additional emission limitation requirements and must explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary combustion turbine).

(e) If you are required to conduct an initial performance test, you must submit a notification of intent to conduct an initial performance test at least 60 calendar days before the initial performance test is scheduled to begin as required in § 63.7(b)(1).

(f) If you are required to comply with the emission limitation for formaldehyde, you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For each performance test required to demonstrate compliance with the emission limitation for formaldehyde, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th calendar day following the completion of the performance test.

[Rules 62-4.070(3) and 62-204.800, F.A.C.; Subparts A and YYYY in 40 CFR 63]

NESHAPS REQUIREMENTS-STATIONARY RECIPROCATING INTERNAL COMBUSTION ENGINES

The emergency fire pump diesel engine and the safe shutdown generator are regulated for purposes of ARMS as Emissions Unit Nos. 010 and 011. These two reciprocating internal combustion engines (RICE) are subject to the notification requirements of 40 CFR 63, Subpart ZZZZ--National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

The complete provisions of Subpart ZZZZ may be provided in full upon request and are also available beginning at Section 63.6580 at:

www.access.gpo.gov/nara/cfr/waisidx_07/40cfr63d_07.html .

Appendix 4: Industrial Wastewater Permit FLA010967

Department of Environmental Protection

Lawton Chiles
Governor

Central District
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767

Virginia B. Wetherell
Secretary

F

CERTIFIED MAIL
P 234 894 478

KISSIMMEE UTILITY AUTHORITY
P O BOX 423219
KISSIMMEE FL 34742

OCD-IW-96-0565

UPDATED
DATE 11-27-96
BY CLG

ATTENTION JAMES C WELSH PRESIDENT

Osceola County - IW
KUA/Cane Island Power Plant
Permit No. FLA010961
Revised Permit

Dear Mr. Welsh:

Enclosed is revised Permit No. FLA010961 previously issued on September 18, 1996. This revised permit supersedes the prior permit in its entirety.

The minor modifications agreed to during our meeting with Mr. Tony Silver and Larry Mattern of your office are included in the revised permit.

If you have any questions, please contact Mr. Ali Kazi, P.E., Program Manager, Industrial Wastewater Program at 407-893-3317.

Sincerely,

Christianne C. Ferraro

Christianne C. Ferraro, P.E.
Program Administrator
Water Facilities

Date: Nov. 18, 1996

CCF/ak/jem

Enclosure

cc: Osceola County Environmental Services
Ground Water Section
Steven Ihnow P.E.

Department of Environmental Protection

Lawton Chiles
Governor

Central District
3319 Maguire Boulevard, Suite 232
Orlando, Florida 32803-3767

Virginia B. Wetherell
Secretary

INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE:

Kissimmee Utility Authority
P. O. Box 423219
Kissimmee, FL 34742
Attention: James C. Welsh, President

PERMIT NO.: FLA010961
FILE NO.: 49-283594
FACILITY I.D. NO.: 3049M06279
ISSUANCE DATE: 11/18/96
EXPIRATION DATE: August 15, 2001

FACILITY:

KUA/Cane Island Power Plant
6075 Old Tampa Highway
1.5 miles Northwest of Intercession City, Osceola County, Florida

Latitude: 26° 16' 29" N Longitude: 81° 31' 50" W

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.) and applicable rules of the Florida Administrative Code (F.A.C.). The above named permittee is hereby authorized to operate the facilities shown on the application and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

Operation of an existing industrial wastewater treatment and disposal system to serve the referenced electric power generation facility. The facility receives a Monthly Average Flow (MAF) of 1.00 MGD from the City of Kissimmee/Bermuda Avenue wastewater treatment facility (POTW). This water supply is designated as INT-01. Well water is at the monthly average rate of 0.205 MGD to supplement the wastewater from the POTW. This supply is designated as INT-02 for well 2A and INT-03 for well 2B. The permittee may alter the flow volumes from INT-01, INT-02 and INT-03 as required for operational needs. The POTW effluent is used for cooling tower makeup water. The wells are used to supply the potable services and the demineralizer systems. This permit also authorizes the relocation of the percolation pond used for onsite discharge to ground water to another portion of the property. The various wastestreams from the operation of the facility are listed as follows:

A. Cooling Tower Blowdown at an approximate daily flow of 0.20 MGD.

B. Neutralization Basin Effluent at a monthly average flow of 0.021 MGD. This consists of :

   1. Ion Exchange Regeneration Wastes.

   2. Chemical/Metal Cleaning Rinses.

   3. Chemical Area Drains.

C. Steam Cycle Blowdown at a MDF of 0.013 MGD.

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Conditions of Certification Appendix 4 - IW Permit FLA010961
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D. Drains from the Turbine Area, Plant and Equipment Areas.

E. Area Drains as follows:

1. Fuel Oil Storage Tank Bermed Containment Area.

2. Transformer Area Containment Bermed Area.

3. Fuel Oil Unloading Station.

F. Roof and Site Drains.

WASTEWATER TREATMENT:

Wastestream B is treated by pH neutralization and settling before mixing with Wastestreams A and C. These three wastestreams are discharged to the POTW effluent forcemain to the Imperial percolation ponds at a MDF of 0.20 MGD. The Imperial site disposal system operates under DEP Domestic Wastewater Permit Number FLA010959 and the South Bermuda Domestic Wastewater treatment facility is under Permit Number FL0041874.

Wastestreams D and E are treated in oil/water separators prior to discharge to Class G-II ground water via percolation in a 127 foot by 62 foot (top of berm) above ground impoundment. There shall be no discharge of these wastestreams to surface waters of the State.

Wastestream F shall be routed to an onsite stormwater management system permitted by the South Florida Water Management District.

There are maintenance manholes containing electrical conduits. These must be dewatered for access by maintenance personnel. The water removed from these manholes is not considered to be industrial wastewater and is not regulated under this permit.

There shall be no discharges from the treatment or disposal system to the surface waters of the State.

EFFLUENT DISPOSAL:

Land Application: A 0.009 MGD monthly average flow, from the treatment system for combined Wastestreams D and E, is land applied in a one cell, above grade percolation impoundment for discharges into Class GII ground water. This outfall is designated Outfall G001. The land application system is located approximately at the latitude and longitude listed above.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions set forth in attached Pages 3 through 14 of this permit.

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I. Effluent Limitations and Monitoring Requirements:

PSLC Pond

A. Land Application Systems:

1. During the period beginning on the effective date of this permit and lasting through the expiration date of this permit, the permittee is authorized to discharge, from Discharge Location G001, wastewater from the industrial wastewater treatment system (Wastestreams D & E) to an impoundment onsite. Samples shall be taken at the sampling port designated G001. Such discharge shall be limited and monitored by the permittee as specified below:

Parameters (Units)	Discharge Limitations (a)			Monitoring Requirements		
	Monthly Avg.	Daily Max.	Other	Frequency	Sample Type	Sample Point
Flow (MGD)	0.009 (b)	Report	NA	Daily	Metered	G001
TDS (mg/l)	Report	Report	NA	Monthly	Grab	G001
Chlorides (mg/l)	Report	Report	NA	Monthly	Grab	G001
Total Nitrogen (mg/l)	Report	Report	NA	Monthly	Grab	G001
Sodium (mg/l)	Report	Report	NA	Monthly	Grab	G001
Sulfates (mg/l)	Report	Report	NA	Monthly	Grab	G001
TRPH (mg/l) (c)	Report	Report	NA	2/ Month	Grab	G001
pH (SU)	See Specific Condition I.A.5					

2. During the period beginning on the effective date of this permit and lasting through the expiration date of this permit, the permittee is authorized to discharge, from Discharge Location G002, wastewater from Wastestreams A, B and C to the City of Kissimmee forcemain to the Imperial land application site. Samples shall be taken at the sampling port designated G002. Such discharge shall be limited and monitored by the permittee as specified below:

Parameters (Units)	Discharge Limitations (a)			Monitoring Requirements		
	Monthly Avg.	Daily Max.	Other	Frequency	Sample Type	Sample Point
Flow (MGD)	0.250	0.275	NA	Daily	Metered	G002
TDS (mg/l)	Report	Report	NA	2/Month	Grab	G002
Chlorides (mg/l)	Report	Report	NA	2/Month	Grab	G002
Nitrates as N (mg/l)	Report	Report	NA	Weekly	Grab	G002
Nitrates as N (#/ day)	Report	Report	NA	Weekly	Grab	G002
Total Nitrogen (mg/l)	Report	Report	NA	Weekly	Grab	G002
Total Nitrogen (#/ day)	Report	Report	NA	Weekly	Grab	G002
Sodium (mg/l)	Report	Report	NA	2/Month	Grab	G002
Sulfates (mg/l)	Report	Report	NA	2/Month	Grab	G002
TRPH (mg/l) (c)	Report	Report	NA	Monthly	Grab	G002
pH (SU)	See Specific Condition I.A.5					

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3. During the period beginning on the effective date of this permit and lasting through the expiration date of this permit, the permittee shall sample the treated domestic effluent from the City of Kissimmee POTW that is used in the power plant. There will be a sampling port established that will be designated location INT-01 to obtain representative samples of this wastewater. Samples shall be taken at Location INT-01 and tested by the permittee as specified below:

Parameters (Units)	Discharge Limitations (a)			Monitoring Requirements		
	Monthly Avg.	Daily Max.	Other	Frequency	Sample Type	Sample Point
Flow (MGD)	Report	Report	NA	Daily	Metered	INT-01
Nitrates as N (#/ day) (d)	Report	Report	NA	Weekly	Grab	INT-01
Nitrates as N (mg/l)	Report	Report	NA	Weekly	Grab	INT-01
Total Nitrogen (#/ day) (d))	Report	Report	NA	Weekly	Grab	INT-01
Total Nitrogen (mg/l)	Report	Report	NA	Weekly	Grab	INT-01

4. During the period beginning on the effective date of this permit and lasting through the expiration date of this permit, the permittee shall sample the raw water supply from the wells onsite that are used in the power plant. There will be sampling ports established that will be designated Locations INT-02 and INT-03 to obtain representative samples of this ground water. These ports shall be located on the lines from Well No. 2A and Well No. 2B respectively. Samples shall be taken at Locations INT-02 and INT-03 and tested by the permittee as specified below:

INT-02

Parameters (Units)	Discharge Limitations (a)			Monitoring Requirements		
	Monthly Avg.	Daily Max.	Other	Frequency	Sample Type	Sample Point
Flow (gpd)	Report	Report	NA	Daily	Metered	INT-02
TDS (mg/l)	Report	Report	NA	Monthly	Grab	INT-02
TSS (mg/l)	Report	Report	NA	Monthly	Grab	INT-02
Surfactants (mg/l)	Report	Report	NA	Monthly	Grab	INT-02
Total Nitrogen (#/day) (d)	Report	Report	NA	Weekly	Grab	INT-02
Total Nitrogen as N (mg/l)	Report	Report	NA	Weekly	Grab	INT-02
Nitrate Nitrogen (#/day) (d)	Report	Report	NA	Weekly	Grab	INT-02
Nitrate Nitrogen (mg/l)	Report	Report	NA	Weekly	Grab	INT-02

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INT-03

Parameters (Units)	Discharge Limitations(a)			Monitoring Requirements		
	Monthly Avg.	Daily Max.	Other	Frequency	Sample Type	Sample Point
Flow (gpd)	Report	Report	NA	Daily	Metered	INT-03
TDS (mg/l)	Report	Report	NA	Monthly	Grab	INT-03
TSS (mg/l)	Report	Report	NA	Monthly	Grab	INT-03
Surfactants (mg/l)	Report	Report	NA	Monthly	Grab	INT-03
Total Nitrogen (#/day) (d)	Report	Report	NA	Weekly	Grab	INT-03
Total Nitrogen as N mg/l	Report	Report	NA	Weekly	Grab	INT-03
Nitrate Nitrogen (#/day) (d)	Report	Report	NA	Weekly	Grab	INT-03
Nitrate Nitrogen mg/l	Report	Report	NA	Weekly	Grab	INT-03

(a) Daily Discharge: The "discharge of a pollutant" measured during a calendar day or any 24 hour period that reasonably represents the calendar day for purposes of sampling. For pollutants with limitations expressed in units of mass, the "daily discharge" is calculated as the total mass of the pollutants discharged over the day. For pollutants expressed in other units of measurements; e.g., concentration, "daily discharge" is calculated as the average measurement of the pollutant over the day.

Average Monthly Discharge Limitation : The highest allowable average of "daily discharges" over a calendar month calculated as the sum of all "daily discharges" measured during a calendar month divided by the number of "daily discharges" measured during that month.

Maximum Daily Discharge Limitation: The highest allowable daily discharge.

(b) The flow limitation does not include the component of the flow that is introduced through thr plant area drains.
(c) Total Recoverable Petroleum Hydrocarbons
(d) See Condition I.A.16.

5. The pH shall not be less than 6.0 standard units, nor greater than 8.5 standard units at any time at Sampling Locations G001 and G002. The pH shall be monitored twice monthly by grab sample at Locations G001 and G002.

6. Unless specified elsewhere in the permit, samples taken in compliance with the monitoring requirements specified in I.A.1. shall be taken at the nearest accessible point after final treatment but prior to the actual discharge to the land application system. The same sampling point shall be used in each sampling event.

7. There shall be no discharge of industrial wastewater from this facility to surface waters.

8. Monitoring results obtained for each calendar month shall be summarized for that period and reported on a Discharge Monitoring Report (DMR), Form 62-620.910(10), postmarked no later than the 28th day of the month following the completed calendar month. For example, data for January shall be submitted by February 28. Signed copies of the DMR shall be submitted to the address specified below:

Florida Department of Environmental Protection Central District Office
Industrial Wastewater Program
3319 Maguire Boulevard, Suite 232
Orlando, FL 32803

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If no discharge occurs during the reporting period, the above sampling requirements of this permit do not apply. The DMR shall be submitted with the statement "No discharge" written on the DMR form. If, during the term period of this permit, the facility ceases to discharge, the Department shall be notified immediately upon cessation of discharge. Such notification shall be in writing.

9. Unless specified otherwise in this permit, all other reports and notifications required by this permit, including twenty- four hour notifications, shall be submitted to or reported to, as appropriate, the Central District Office of the Department at the address specified above.

10. Grab samples shall be collected during periods of minimal treatment plant pollutant removal efficiencies or maximum hydraulic and/or pollutant loading.

11. The permittee shall provide safe access points for obtaining representative samples which are required by this permit.

12. The permittee shall ensure that all laboratory analytical data submitted to the department as required by this permit is from a laboratory which has a currently valid and Department-approved Comprehensive Quality Assurance Plan (ComQAP) [or a ComQAP pending approval] for all parameters being reported as required by Chapter 62-160, Florida Administrative Code.

13. If there is no discharge from the facility on a day scheduled for sampling, the sample shall be collected on the day of the next discharge.

14. Any bypass of the treatment facility which is not included in the monitoring specified in I.A.1. above is to be monitored for flow and all other required parameters. For parameters other than flow, at least one grab sample per day shall be monitored. Daily flow shall be monitored or estimated, as appropriate, to obtain reasonable data. All monitoring results shall be reported on the appropriate DMR.

15. Sampling shall commence in accordance with the requirements of this permit in the first month following the month in which the permit is issued.

16. There shall be no net increase of total Nitrogen and Total Nitrates as N in pounds per day, on an annual basis, introduced back into the City's forcemain to the Imperial disposal site than was recieved from the City in the domestic effluent water used for supply. Calculations shall be made on the following basis: Total weekly flow in Million Gallons x 8.34 x concentration in mg/l for each parameter.

II. Industrial Sludge Management Requirements

A. Basic Management Requirements:

1. There will be no residual solids generated in the treatment/ disposal process at this facility.

2. Waste oil removed from any treatment unit in this system shall be stored onsite in a separate waste oil tank. The stored waste oil shall be managed and ultimately disposed of by a licensed used oil recycler in accordance with the provisions of Chapter 62-710, F.A.C.

3. Mixing of any waste product generated from this system with septage or domestic residuals is prohibited.

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III. Groundwater Monitoring Requirements

A. Groundwater Monitoring requirements:

1. During the period of operation authorized by this permit, the permittee shall sample ground water in accordance with this permit and the approved ground water monitoring plan prepared in accordance with Rule 62-522.600, F.A.C. [62-522.600, 4/14/94]
2. The following monitoring wells shall be sampled quarterly:

Well Name	Monitoring Location Site Number	WAFR Number	Depth (Feet)	Aquifer Monitored	Well Type	New or Existing
MW-1	3049A17007	6240	18	Shallow	Background	Existing
MW-5	3049A17008	6239	42	Shallow	Compliance	Existing
MW-6	3049A17009	6238	35	Shallow	Compliance	Existing

3. The following parameters shall be analyzed quarterly for each of the monitoring well(s) identified in Item III. 2.:

   a. Water level (field measurement)
   b. pH
   c. Sodium
   d. Chloride
   e. TDS
   f. Turbidity
   g. TRPH
   h. Nitrate Nitrogen
   i. Sulfate

   [62-522.600(11)(b), 4/1/94]

4. All sampling shall be conducted using standard DEP sampling procedures.[62-4.426]

5. In accordance with Part D of Form 62-620.910(10), water levels shall be recorded before evacuating the wells for sample collection. Elevation references shall include the top of the well casing and land surface at each well site (NVGD) at a precision of plus or minus 0.1 foot.

6. Ground water monitoring wells shall be evacuated or purged prior to sampling to obtain a representative sample.

7. Analyses shall be conducted on un-filtered samples, unless filtered samples have been approved by the Department as being more representative of ground water conditions.

8. If a monitoring well becomes damaged or cannot be sampled for some reason, the permittee shall notify the Department with a written report within seven days detailing the circumstances and remedial measures taken or proposed. Replacement of monitoring wells shall be approved in advance by the Department.

9. Ground water monitoring test results shall be submitted on Part D of Form 62-620.910(10). Results shall be submitted with the April, July, October and January DMR's for each year during the period of operation allowed by this permit. [62-522.600(10) and (11)(b), 4/14/94 [62-620.610(18), 11-29-94]

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IV. Other Land Application Requirements

A. The permittee's discharge to ground water shall not cause a violation of water quality standards for Class G-II ground waters at the boundary of the zone of discharge in accordance with rules 62-520.400 and 62-520.420, F.A.C.

B. The permittee's discharge to ground water shall not cause a violation of the minimum criteria for ground water specified in rule 62-520.400, F.A.C., within the zone of discharge.

C. The frequency and rate of effluent disposal shall be managed by the permittee to avoid secondary environmental impacts such as severe odors and other nuisance conditions.

V. Operation and Maintenance Requirements

A. Operation of Treatment and Disposal Facilities:

1. The permittee shall ensure that the operation of this facility is as described in the application and supporting documents.

2. The operation of the pollution control facilities described in this permit shall be under the full time supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control.

B. Record keeping Requirements:

The permittee shall maintain the following records on the site of the permitted facility and make them available for inspection:

1. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;

2. Copies of all reports, other than those required in items 1. and 6. of this section, required by the permit for at least three years from the date the report was prepared, unless otherwise specified by Department rule;

3. Records of all data, including reports and documents used to complete the application for the permit for at least three years from the date the application was filed, unless otherwise specified by Department rule;

4. A copy of the current permit;

5. A copy of any required record drawings;

6. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date on the logs or schedule.

VI. Compliance Schedules and Self-imposed Improvement Schedules

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A. The permittee shall achieve compliance with the terms of this permit in accordance with the following schedule:

Operational compliance shall be attained within 15 days of issuance of this permit.

VII. Other Specific Conditions

A. Specific Conditions Applicable to all permits:

1. Drawings, plans, documents or specifications submitted by the permittee, not attached hereto, but retained on file at the Central District Office, are made a part hereof.

2. If significant historical or archaeological artifacts are discovered at any time within the project site, the permittee shall immediately notify the District Office and the Bureau of Historic Preservation, Division of Archives, History and Records Management, R.A. Gray Building, Tallahassee, Florida 32301.

3. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of reports to be submitted under this permit, shall be signed and sealed by the professional(s) who prepared them.

4. This permit satisfies Industrial Wastewater program permitting requirements only and does not authorize operation of this facility prior to obtaining any other permits required by local, state or federal agencies.

B. Duty to Reapply:

1. The permittee shall submit an application to renew this permit at least 180 days before the expiration date of this permit.

2. The permittee shall apply on the appropriate form listed in Rule 62-620.910, F.A.C., and in the manner established in Rules 62-620.400 through 62-620.460, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.

3. An application filed in accordance with subsections 1. and 2. of this part shall be considered timely and sufficient. When an application for renewal of a permit is timely and sufficient, the existing permit shall not expire until the Department has taken final action on the application for renewal or until the last day for seeking judicial review of the agency order or a later date fixed by order of the reviewing court.

4. The late submittal of a renewal application shall be considered timely and sufficient for the purpose of extending the effectiveness of the expiring permit only if it is submitted and made complete before the expiration date.

C. Specific Conditions Related to Best Management Practices Condition:

1. BMP Plan: For purposes of this part, the terms "pollutant" or "pollutants" refer to any substance listed as toxic under Section 307(a)(1) of the Clean Water Act (the "Act"), oil, as defined in Section 311(a)(1) of the Act, and any substance listed as hazardous under Section 311 of the act. The permittee shall develop and implement a Best Management Practices (BMP) plan which prevents, or minimizes the potential for, the release of pollutants from ancillary activities, including material storage areas; plant site runoff; in-plant transfer, process and material handling areas; loading and unloading operations; and sludge and waste disposal areas, to the waters of the State through plant site runoff; spillage or leaks; sludge or waste disposal; or drainage from raw material storage.

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2. Implementation: The plan shall be developed within six months after the issuance date of this permit and shall be implemented as soon as practicable but not later than 18 months after the issuance date of the permit. The permittee shall submit written notification of compliance or noncompliance with these requirements to the Department in accordance with part I.A.8. of this permit.

3. General Requirements: The BMP plan shall:

   a. Be documented in narrative form, and shall include any necessary plot plans, drawings or maps.

   b. Establish specific objectives for the control of pollutants.

      (1) Each facility component or system shall be examined for its potential for causing a release of significant amounts of pollutants to waters of the State due to equipment failure, improper operation, natural phenomena such as rain or snowfall, etc.

      (2) Where experience indicates a reasonable potential for equipment failure (e.g., a tank overflow or leakage), natural conditions (e.g., precipitation), or other circumstances to result in significant amounts of pollutants reaching surface waters, the plan should include a prediction of the direction, rate of flow, and total quantity of pollutants which could be discharged from the facility as a result of each condition or circumstance.

   c. Establish specific best management practices to meet the objectives identified under paragraph b of this subsection, addressing each component or system capable of causing a release of significant amounts of pollutants to the waters of the State, and identifying specific preventative or remedial measures to be implemented.

   d. Include any special conditions established in Section B of this part.

   e. Be reviewed by plant engineering staff and plant manager.

4. Documentation: The permittee shall maintain the BMP plan at the facility and shall make the plan available to the Department upon request.

5. BMP Plan Modification: The permittee shall amend the BMP plan whenever there is a change in the facility or change in the operation of the facility which materially increases the potential for the ancillary activities to result in a discharge of significant amounts of pollutants.

6. Modification for Ineffectiveness: If the BMP plan proves to be ineffective in achieving the general objective of preventing the release of significant amounts of pollutants to surface waters and the specific objectives and requirements under paragraphs b and c of item 3., the permit shall be subject to modification pursuant to rule 62-620.325, F.A.C., to incorporate revised BMP requirements.

VIII. General Conditions

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, Florida Statutes. Any permit noncompliance constitutes a violation of Chapter 403, Florida Statutes, and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. [62-620.610(1)]

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2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviations from the approved drawings, exhibits, specifications or conditions of this permit constitutes grounds for revocation and enforcement action by the Department. [62-620.610(2)]

3. As provided in Subsection 403.087(6), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor authorize any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit or authorization that may be required for other aspects of the total project which are not addressed in this permit. [62-620.610(3)]

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. [62-620.610(4)]

5. This permit does not relieve the permittee from liability and penalties for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted source; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department. The permittee shall take all reasonable steps to minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. [62-620.610(5)]

6. If the permittee wishes to continue an activity regulated by this permit after its expiration date, the permittee shall apply for and obtain a new permit. [62-620.610(6)]

7. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control, and related appurtenances, that are installed and used by the permittee to achieve compliance with the conditions of this permit. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to maintain or achieve compliance with the conditions of the permit. [62-620.610(7)]

8. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. [62-620.610(8)]

9. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to:

   a. Enter upon the permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under the conditions of this permit;

   b. Have access to and copy any records that shall be kept under the conditions of this permit;

   c. Inspect the facilities, equipment, practices, or operations regulated or required under this permit; and

   d. Sample or monitor any substances or parameters at any location necessary to assure compliance with this permit or Department rules. [62-620.610(9)]

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10. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data, and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except as such use is proscribed by Section 403.111, Florida Statutes, or Rule 62-620.302, Florida Administrative Code. Such evidence shall only be used to the extent that it is consistent with the Florida Rules of Civil Procedure and applicable evidentiary rules. [62-620.610(10)]

11. When requested by the Department, the permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also provide to the Department upon request copies of records required by this permit to be kept. If the permittee becomes aware of relevant facts that were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department. [62-620.610(11)]

12. Unless specifically stated otherwise in Department rules, the permittee, in accepting this permit, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard. [62-620.610(12)]

13. The permittee, in accepting this permit, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C. [62-620.610(13)]

14. This permit is transferable only upon Department approval in accordance with Rule 62-620.340, F.A.C. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department. [62-620.610(14)]

15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. [62-620.610(15)]

16. The permittee shall apply for a revision to the Department permit in accordance with Rules 62-620.300, 62-620.420 or 62.620.450, F.A.C., as applicable, at least 90 days before construction of any planned substantial modifications to the permitted facility is to commence or with Rule 62-620.300 for minor modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in Rule 62-620.330, F.A.C. [62-620.610(16)]

17. The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. The permittee shall be responsible for any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of this permit. The notice shall include the following information:

    a. A description of the anticipated noncompliance;

    b. The period of the anticipated noncompliance, including dates and times; and

    c. Steps being taken to prevent future occurrence of the noncompliance. [62-620.610(17)]

18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246, Chapter 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate.

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a. Monitoring results shall be reported at the intervals specified elsewhere in this permit and shall be reported on a Discharge Monitoring Report (DMR), DEP Form 62-620.910(10).

b. If the permittee monitors any contaminate more frequently than required by the permit, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

c. Calculations for all limitations which require averaging of measurements shall use an arithmetic mean unless otherwise specified in this permit.

d. Any laboratory test required by this permit for domestic wastewater facilities shall be performed by a laboratory that has been certified by the Department of Health and Rehabilitative Services (DHRS) under Chapter 10D-41, F.A.C., to perform the test. In domestic wastewater facilities, on-site tests for dissolved oxygen, pH, and total chlorine residual shall be performed by a laboratory certified to test for those parameters or under the direction of an operator certified under Chapter 61E12-41, F.A.C.

e. Under Chapter 62-160, F.A.C., sample collection shall be performed by following the protocols outlined in "DER Standard Operating Procedures for Laboratory Operations and Sample Collection Activities" (DER-QA-001/92). Alternatively, sample collection may be performed by an organization who has an approved Comprehensive Quality Assurance Plan (CompQAP) on file with the Department. The CompQAP shall be approved for collection of samples from the required matrices and for the required tests. [62-620.610(18)]

19. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in this permit shall be submitted no later than 14 days following each schedule date. [62-620.610(19)]

20. The permittee shall report to the Department any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances.

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The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance including exact dates and time, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

a. The following shall be included as information which must be reported within 24 hours under this condition:

(1) Any unanticipated bypass which causes any reclaimed water or the effluent to exceed any permit limitation or results in an unpermitted discharge,

(2) Any upset which causes any reclaimed water or the effluent to exceed any limitation in the permit,

(3) Violation of a maximum daily discharge limitation for any of the pollutants specifically listed in the permit for such notice, and

(4) Any unauthorized discharge to surface or ground waters.

b. If the oral report has been received within 24 hours, the noncompliance has been corrected, and the noncompliance did not endanger health or the environment, the Department shall waive the written report. [62-620.610(20)]

21. The permittee shall report all instances of noncompliance not reported under Conditions VIII. 18 and 19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Condition VIII. 20 of this permit. [62-620.610(21)]

22. Bypass Provisions.

a. Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless the permittee affirmatively demonstrates that:

(1) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(2) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and

(3) The permittee submitted notices as required under Condition VIII. 22.b of this permit.

b. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least 10 days before the date of the bypass. The permittee shall submit notice of an unanticipated bypass within 24 hours of learning about the bypass as required in Condition VIII. 20 of this permit. A notice shall include a description of the bypass and its cause; the period of the bypass, including exact dates and times; if the bypass has not been corrected, the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the bypass.

c. The Department shall approve an anticipated bypass, after considering its adverse effect, if the permittee demonstrates that it will meet the three conditions listed in Condition VIII. 22.a(1) through (3) of this permit.

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d. A permittee may allow any bypass to occur which does not cause reclaimed water or effluent limitations to be exceeded if it is for essential maintenance to assure efficient operation. These bypasses are not subject to the provision of Condition VIII. 22.a through c of this permit. [62-620.610(22)]

23. Upset Provisions

a. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed contemporaneous operating logs, or other relevant evidence that:

(1) An upset occurred and that the permittee can identify the cause(s) of the upset;

(2) The permitted facility was at the time being properly operated;

(3) The permittee submitted notice of the upset as required in Condition VIII. 20. of this permit; and

(4) The permittee complied with any remedial measures required under Condition VIII. 5. of this permit.

b. In any enforcement proceeding, the permittee seeking to establish the occurrence of an upset has the burden of proof.

c. Before an enforcement proceeding is instituted, no representation made during the Department review of a claim that noncompliance was caused by an upset is final agency action subject to judicial review. [62-620.610(23)]

Executed in Orlando, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Christianne C. Ferraro

Christianne C. Ferraro, P.E.
Program Administrator
Water Facilities

DATE: Nov. 18, 1996

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Conditions of Certification Appendix 4 - IW Permit FLA010961

WHEN COMPLETED MAIL THIS REPORT TO: Department of Environmental Protection **Central District**
Industrial Wastewater, Ste 200B, **3319 Maguire Blvd. Orlando, FL 32803-3767**
PERMITTEE NAME: Kissimmee Utility Authority
MAILING ADDRESS: P.O.Box 423219
Kissimmee, FL. 34742
Attn.: James C. Welsh, President.
FACILITY: KUA/ Cane Island Power Plant
LOCATION: 6075 Old Tampa Hwy, 1.5 miles NW of Intercession City
COUNTY Osceola

Sampling port on discharge line to the on site percolation pond
PERMIT NUMBER: FLA010961
MONITORING PERIOD--From: To:
LIMIT: Final
CLASS SIZE:NA
FACILITY ID: FLA010961 GROUP: IW
GMS ID NO. 3049M06279
DISCHARGE POINT NUMBER: G001 WAFR SITE NO. 6236
PLANT SIZE/TREATMENT TYPE: NA

Please read instructions before completing this form.

Parameter		Quantity or Loading			Quality or Concentration				No. Ex.	Frequency of Analysis	Sample Type
		Avg.	Max.	Units	Min.	Avg.	Max.	Units			
Flow Storet No. 50053 Mon. Site No. G001	Sample Measurement										
	Permit Requirement	0.009*	Report	MGD						Daily	Metered
TDS Storet No. 00525 Mon. Site No. G001	Sample Measurement										
	Permit Requirement					Report	Report	mg/l		Monthly	Grab
Chlorides Storet No. 00940 Mon. Site No. G001	Sample Measurement										
	Permit Requirement					Report	Report	mg/l		Monthly	Grab
Total Nitrogen Storet No. 00600 Mon. Site No. G001	Sample Measurement										
	Permit Requirement					Report	Report	mg/l		Monthly	Grab
Sodium Storet No. 00929 Mon. Site No. G001	Sample Measurement										
	Permit Requirement					Report	Report	mg/l		Monthly	Grab
Sulfates Storet No. 00945 Mon. Site No. G001	Sample Measurement										
	Permit Requirement					Report	Report	mg/l		Monthly	Grab

* This flow volume is that amount in excess of the rainfall / stormwater runoff component.

I certify under penalty of law that I have personally examined and am familiar with the information submitted herein; and based on my inquiry of those individuals immediately responsible for obtaining the information, I believe the submitted information is true, accurate and complete. I am aware that there are significant penalties for submitting false information including the possibility of fine and imprisonment.

Name/Title of Principal Executive Officer or Authorized Agent (Type or Print)	Signature of Principal Executive officer Or Authorized Agent	Telephone No. (include area code)	Date (yy/mm/dd)

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Please read instructions before completing this form.

Parameter		Quantity or Loading			Quality or Concentration				No. Ex.	Frequency of Analysis	Sample Type
		Avg.	Max.	Units	Min.	Avg.	Max.	Units			
Total Recoverable Petroleum Hydrocarbons	Sample Measurement										
Storet No. 31666 Mon. Site No. G001	Permit Requirement					Report	Report	mg/l		2/ Month	Grab
pH	Sample Measurement										
Storet No. 00400 Mon. Site No. G001	Permit Requirement				6.0		8.5	SU		2/ Month	Grab
	Sample Measurement										
Storet No. Mon. Site No.	Permit Requirement										
	Sample Measurement										
Storet No. Mon. Site No.	Permit Requirement										
	Sample Measurement										
Storet No. Mon. Site No.	Permit Requirement										
	Sample Measurement										
Storet No. Mon. Site No.	Permit Requirement										
	Sample Measurement										
Storet No. Mon. Site No.	Permit Requirement										
	Sample Measurement										
Storet No. Mon. Site No.	Permit Requirement										
	Sample Measurement										
Storet No. Mon. Site No.	Permit Requirement										

Conditions of Certification Appendix 4 - IW Permit FLA010961

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NOV 18 1996

WHEN COMPLETED MAIL THIS REPORT TO: Department of Environmental ProtectionCentral District
Industrial Wastewater, Ste 200B, 3319 Maguire Blvd. Orlando, FL 32803-3767
PERMITTEE NAME: Kissimmee Utility Authority
MAILING ADDRESS: P.O.Box 423219
Kissimmee, FL. 34742
Attn.: James C. Welsh, President
FACILITY: KUA/ Cane Island Power Plant
LOCATION: 6075 Old Tampa Hwy, 1.5 miles NW of Intercession City
COUNTY Osceola

Sampling port on discharge line to the force main to the Imperial site
PERMIT NUMBER: FLA010961
MONITORING PERIOD--From: To:
LIMIT: Final
CLASS SIZE:NA
FACILITY ID: FLA010961 GROUP: IW
GMS ID NO. 3049M06279
DISCHARGE POINT NUMBER: G002 WAFR SITE NO. 6235
PLANT SIZE/TREATMENT TYPE: NA

Please read instructions before completing this form.

Parameter		Quantity or Loading			Quality or Concentration				No. Ex.	Frequency of Analysis	Sample Type
		Avg.	Max.	Units	Min.	Avg.	Max.	Units			
Flow Storet No. 50053 Mon. Site No. G002	Sample Measurement										
	Permit Requirement	0.250	0.275	MGD						Daily	Metered
TDS Storet No. 00525 Mon. Site No. G002	Sample Measurement										
	Permit Requirement					Report	Report	mg/l		2/ Month	Grab
Chlorides Storet No. 00940 Mon. Site No. G002	Sample Measurement										
	Permit Requirement					Report	Report	mg/l		2/ Month	Grab
Nitrates as N Storet No. 00620 Mon. Site No. G002	Sample Measurement										
	Permit Requirement					Report*	Report*	mg/l		Weekly	Grab
Nitrates as N, Calculate and Report Storet No. NA Mon. Site No. G002	Sample Measurement										
	Permit Requirement	Report	Report	#/Day						Weekly	Grab
Nitrogen Total Storet No. 00600 Mon. Site No. G002	Sample Measurement										
	Permit Requirement					Report*	Report*	mg/l		Weekly	Grab

There shall be no net increase of Total Nitrogen or Nitrate Nitrogen over the combined influent streams in pounds per day on an annual average.

I certify under penalty of law that I have personally examined and am familiar with the information submitted herein; and based on my inquiry of those individuals immediately responsible for obtaining the information, I believe the submitted information is true, accurate and complete. I am aware that there are significant penalties for submitting false information including the possibility of fine and imprisonment.

Name/Title of Principal Executive Officer or Authorized Agent (Type or Print)	Signature of Principal Executive officer Or Authorized Agent	Telephone No. (includeareacode)	Date (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

Conditions of Certification Appendix 4 - IW Permit FLA010961*

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ADDITIONAL SHEET 1 **KUA/ Cane Island Power Plant** **Facility ID FLA010559 Discharge Point # G002**

Please read instructions before completing this form.

Parameter		Quantity or Loading			Quality or Concentration				No. Ex.	Frequency of Analysis	Sample Type
		Avg.	Max.	Units	Min.	Avg.	Max.	Units			
Nitrogen (Total), Calculate and Report	Sample Measurement										
Storet No. NA Mon. Site No. G002	Permit Requirement	Report	Report	#/Day						Weekly	Grab
Sodium	Sample Measurement										
Storet No. 00929 Mon. Site No. G002	Permit Requirement					Report	Report	mg/l		2/ Month	Grab
Sulfates	Sample Measurement										
Storet No. 00945 Mon. Site No. G002	Permit Requirement					Report	Report	mg/l		2/ Month	Grab
TRPH	Sample Measurement										
Storet No. 31666 Mon. Site No. G002	Permit Requirement					Report	Report	mg/l		Weekly	Grab
pH	Sample Measurement										
Storet No. 00400 Mon. Site No. G002	Permit Requirement				6.0		8.5	SU		2/ Month	Grab
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										

Conditions of Certification Appendix 4 - IW Permit FLA010961

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DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

WHEN COMPLETED MAIL THIS REPORT TO: Department of Environmental ProtectionCentral District
Industrial Wastewater, Ste 200B, 3319 Maguire Blvd. Orlando, FL 32803-3767

PERMITTEE NAME: Kissimmee Utility Authority
MAILING ADDRESS: P.O.Box 423219
Kissimmee, FL. 34742
Attn.: James C. Welsh, President.
FACILITY: KUA/ Cane Island Power Plant
LOCATION: 6075 Old Tampa Hwy, 1.5 miles NW of Intercession City
COUNTY Osceola

Sampling port on the wastewater forcemain from the POTW
PERMIT NUMBER: FLA010961
MONITORING PERIOD--From: To:
LIMIT: Final
CLASS SIZE:NA
FACILITY ID: FLA010961 GROUP: IW
GMS ID NO. 3049M06279
DISCHARGE POINT NUMBER: INT-01 WAFR SITE NO.6234
PLANT SIZE/TREATMENT TYPE: NA

Parameter		Quantity or Loading			Quality or Concentration				No. Ex.	Frequency of Analysis	Sample Type
		Avg.	Max.	Units	Min.	Avg.	Max.	Units			
Flow	Sample Measurement										
Storet No. 50053 Mon. Site No. INT-01	Permit Requirement	1.0	1.10	MGD						Daily	Metered
Nitrates as N, Calculate and Report	Sample Measurement										
Storet No. NA Mon. Site No. INT-01	Permit Requirement	Report	Report	#/Day						Weekly	Grab
Nitrates as N	Sample Measurement										
Storet No. 00620 Mon. Site No. INT-01	Permit Requirement					Report	Report	mg/l		Weekly	Grab
Total Nitrogen, Calculate and Report	Sample Measurement										
Storet No. NA Mon. Site No. INT-01	Permit Requirement	Report	Report	#/Day						Weekly	Grab
Total Nitrogen	Sample Measurement										
Storet No. 00600 Mon. Site No. INT-01	Permit Requirement					Report	Report	mg/l		Weekly	Grab

I certify under penalty of law that I have personally examined and am familiar with the information submitted herein; and based on my inquiry of those individuals immediately responsible for obtaining the information, I believe the submitted information is true, accurate and complete. I am aware that there are significant penalties for submitting false information including the possibility of fine and imprisonment.

Name/Title of Principal Executive Officer or Authorized Agent (Type or Print)	Signature of Principal Executive officer Or Authorized Agent	Telephone No. (includeareacode)	Date (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

REVISED

NOV 18 1996

Conditions of Certification Appendix 4 - IW Permit FLA010961

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

WHEN COMPLETED MAIL THIS REPORT TO: Department of Environmental ProtectionCentral District
Industrial Wastewater, Ste 200B, 3319 Maguire Blvd. Orlando, FL 32803-3767

PERMITTEE NAME: Kissimmee Utility Authority
MAILING ADDRESS: P.O.Box 423219
Kissimmee, FL. 34742
Attn.: James C. Welsh, President.
FACILITY: KUA/ Cane Island Power Plant
LOCATION: 6075 Old Tampa Hwy, 1.5 miles NW of Intercession City
COUNTY Osceola

Sampling port on the on site water supply well
PERMIT NUMBER: FLA010961
MONITORING PERIOD--From: To:
LIMIT: Final
CLASS SIZE:NA
FACILITY ID: FLA010961 GROUP: IW
GMS ID NO. 3049M06279
DISCHARGE POINT NUMBER: INT-02 WAFR SITE NO.6233
PLANT SIZE/TREATMENT TYPE: NA

Please read instructions before completing this form.

Parameter		Quantity or Loading			Quality or Concentration				No. Ex.	Frequency of Analysis	Sample Type
		Avg.	Max.	Units	Min.	Avg.	Max.	Units			
Flow	Sample Measurement										
Storet No. 50053 Mon. Site No. INT-02	Permit Requirement	Report	Report	MGD						Daily	Metered
Nitrates as N, Calculate and Report	Sample Measurement										
Storet No. NA Mon. Site No. INT-02	Permit Requirement	Report	Report	#/Day						Weekly	Grab
Nitrates as N	Sample Measurement										
Storet No. 00620 Mon. Site No. INT-02	Permit Requirement					Report	Report	mg/l		Weekly	Grab
Total Nitrogen, Calculate and Report	Sample Measurement										
Storet No. NA Mon. Site No. INT-02	Permit Requirement	Report	Report	#/Day						Weekly	Grab
Total Nitrogen	Sample Measurement										
Storet No. 00600 Mon. Site No. INT-02	Permit Requirement					Report	Report	mg/l		Weekly	Grab
Surfactants	Sample Measurement										
Storet No. 01288 Mon. Site No. INT-02	Permit Requirement					Report	Report	mg/l		Monthly	Grab

I certify under penalty of law that I have personally examined and am familiar with the information submitted herein; and based on my inquiry of those individuals immediately responsible for obtaining the information, I believe the submitted information is true, accurate and complete. I am aware that there are significant penalties for submitting false information including the possibility of fine and imprisonment.

Name/Title of Principal Executive Officer or Authorized Agent (Type or Print)	Signature of Principal Executive officer Or Authorized Agent	Telephone No. (include area code)	Date (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

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ADDITIONAL SHEET 1 **KUA/ Cane Island Power Plant** **Facility ID FLA010961 Discharge Point # INT-02**

Please read instructions before completing this form.

Parameter		Quantity or Loading			Quality or Concentration				No. Ex.	Frequency of Analysis	Sample Type
		Avg.	Max.	Units	Min.	Avg.	Max.	Units			
TDS	Sample Measurement										
Storet No. 00525 Mon. Site No. INT-02	Permit Requirement					Report	Report	mg/l		Monthly	Grab
TSS	Sample Measurement										
Storet No. 00530 Mon. Site No. INT-02	Permit Requirement					Report	Report	mg/l		Monthly	Grab
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										

Conditions of Certification Appendix 4 - IW Permit FLA010961

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DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

WHEN COMPLETED MAIL THIS REPORT TO: Department of Environmental ProtectionCentral District
Industrial Wastewater, Ste 200B, 3319 Maguire Blvd. Orlando, FL 32803-3767

PERMITTEE NAME: Kissimmee Utility Authority
MAILING ADDRESS: P.O.Box 423219
Kissimmee, FL. 34742
Attn.: James C. Welsh, President.
FACILITY: KUA/ Cane Island Power Plant
LOCATION: 6075 Old Tampa Hwy, 1.5 miles NW of Intercession City
COUNTY Osceola

Sampling port on the on site water supply well No. 2B
PERMIT NUMBER: FLA010961
MONITORING PERIOD--From: To:
LIMIT: Final
CLASS SIZE:NA
FACILITY ID: FLA010961 GROUP: IW
GMS ID NO. 3049M06279 GMS SITE No. 3049X17745
DISCHARGE POINT NUMBER: INT-03 WAFR SITE NO. 27006
PLANT SIZE/TREATMENT TYPE: NA

Please read instructions before completing this form.

Parameter		Quantity or Loading			Quality or Concentration				No. Ex.	Frequency of Analysis	Sample Type
		Avg.	Max.	Units	Min.	Avg.	Max.	Units			
Flow	Sample Measurement										
Storet No. 50053 Mon. Site No. INT-03	Permit Requirement	Report	Report	MGD						Daily	Metered
Nitrates as N, Calculate and Report	Sample Measurement										
Storet No. NA Mon. Site No. INT-03	Permit Requirement	Report	Report	#/Day						Weekly	Grab
Nitrates as N	Sample Measurement										
Storet No. 00620 Mon. Site No. INT-03	Permit Requirement					Report	Report	mg/l		Weekly	Grab
Total Nitrogen, Calculate and Report	Sample Measurement										
Storet No. NA Mon. Site No. INT-03	Permit Requirement	Report	Report	#/Day						Weekly	Grab
Total Nitrogen	Sample Measurement										
Storet No. 00600 Mon. Site No. INT-03	Permit Requirement					Report	Report	mg/l		Weekly	Grab

I certify under penalty of law that I have personally examined and am familiar with the information submitted herein; and based on my inquiry of those individuals immediately responsible for obtaining the information, I believe the submitted information is true, accurate and complete. I am aware that there are significant penalties for submitting false information including the possibility of fine and imprisonment.

Name/Title of Principal Executive Officer or Authorized Agent (Type or Print)	Signature of Principal Executive officer Or Authorized Agent	Telephone No. (includeareacode)	Date (yy/mm/dd)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

REVISED

NOV 18 1996

Conditions of Certification Appendix 4 - IW Permit FLA010961

ADDITIONAL SHEET 1 **KUA/ Cane Island Power Plant** **Facility ID FLA010961 Discharge Point # INT-03**

Please read instructions before completing this form.

Parameter		Quantity or Loading			Quality or Concentration				No. Ex.	Frequency of Analysis	Sample Type
		Avg.	Max.	Units	Min.	Avg.	Max.	Units			
TDS	Sample Measurement										
Storet No. 00525 Mon. Site No. INT-03	Permit Requirement					Report	Report	mg/l		Monthly	Grab
TSS	Sample Measurement										
Storet No. 00530 Mon. Site No. INT-03	Permit Requirement					Report	Report	mg/l		Monthly	Grab
Surcactants	Sample Measurement										
Storet No. 01288 Mon. Site No. INT-03	Permit Requirement					Report	Report	mg/l		Monthly	Grab
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										
Storet No. Mon. Site No.	Sample Measurement										
	Permit Requirement										

Conditions of Certification Appendix 4 - IW Permit FLA010961

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DAILY SAMPLE RESULTS - PART B

Facility ID: 3049M06279 Permit No.: FLA010961
Month/Year:

Three-month Average Daily Flow:
Daily Flow % of Permitted Capacity:

Days of the Month Parameter/Units	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30/31
Flow to the percloation pond MGD																														
Flow to the City Force main MGD																														
Flow received from the City Force Main																														
Flow from the on site supply well 2A																														
Flow from the on site supply well 2B																														

PLANT STAFFING:

Day Shift Operator	Class:	Certificate No.:	Name:	
Evening Shift Operator	Class:	Certificate No.:	Name:	
Night Shift Operator	Class:	Certificate No.:	Name:	
Lead Operator	Class:	Certificate No.:	Name:	

Type of Effluent Disposal or Reclaimed Water Reuse:
Limited Wet Weather Discharge Activated: ☐ Yes ☐ No If yes, cumulative days of wet weather discharge:
Well 2A is sampling point INT-02, Well 2B is sampling point INT-03

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