Golder Associates Inc.

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Gainesville, FL 32653-1500
Telephone (352) 336-5600
Fax (352) 336-6603

June 4, 2002

0139517-0100

RECEIVED
JUN 05 2002
BUREAU OF AIR REGULATION

Florida Department of Environmental Protection
111 South Magnolia Drive, Suite 4
Magnolia Park Courtyard
Tallahassee, FL 32301

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

RE: SHADY HILLS GENERATING STATION (FACILITY ID - 1010373)
TITLE V AIR OPERATING PERMIT APPLICATION (1010373-003-AV)
ADDITIONAL INFORMATION

Dear Scott:

This letter is submitted on behalf of Shady Hills Generating Station located in Pasco County to transmit additional information requested in the Department's May 29, 2002 letter. Attached please find summaries of the compliance tests for Units 1, 2 and 3 that demonstrate compliance with the emission limits established for the project. These tests were conducted at 100 percent load, which was approved by the Department. I have also attached a copy of the Department's approval of one load testing. The complete test reports were submitted to the Department's Southwest District Office as indicated in the Title V application.

Please call me at (352) 336-5600 if you have any questions.

Sincerely,

GOLDER ASSOCIATES INC.

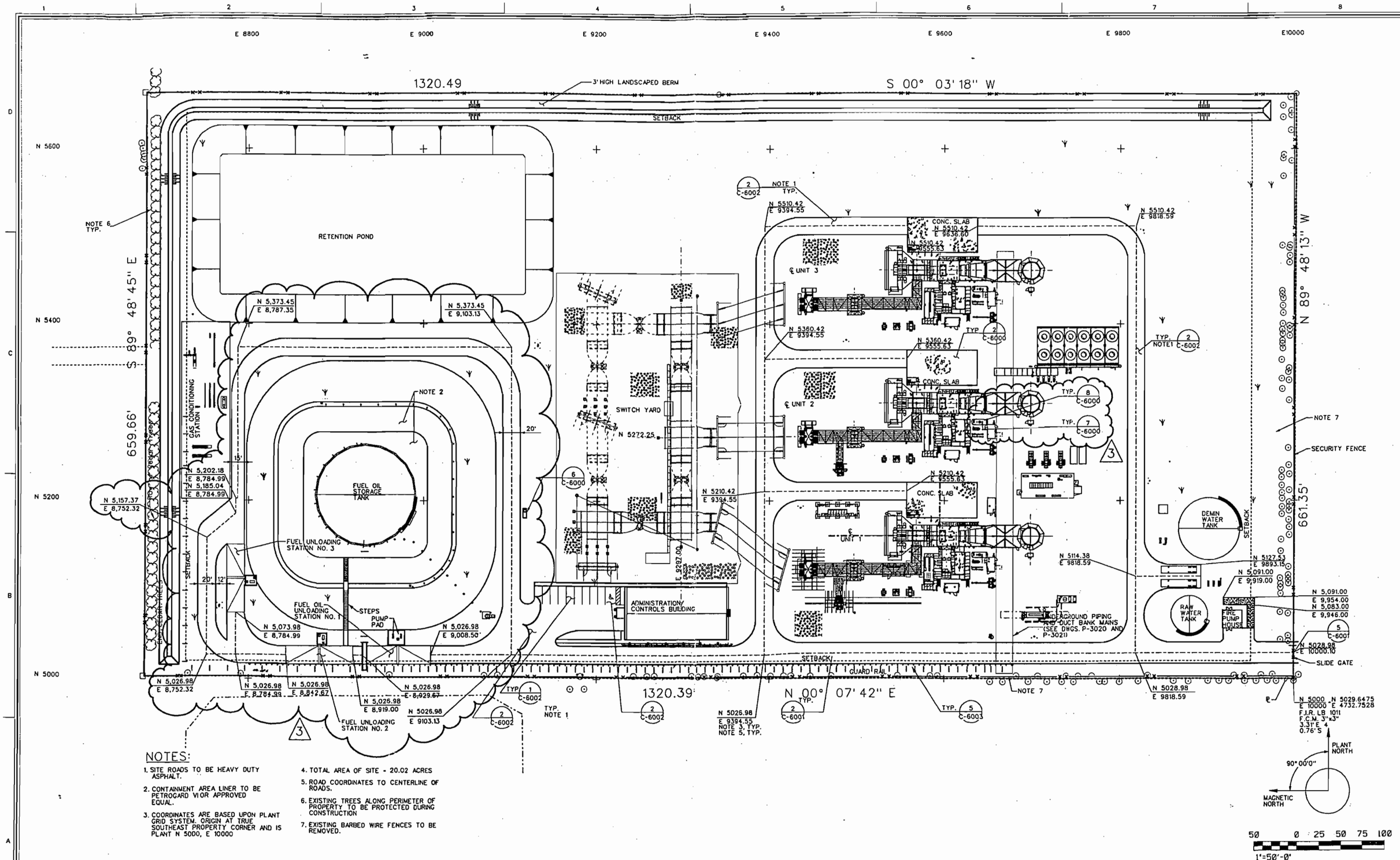
Kennard F. Kosky, P.E.
Principal

KFK/kk

4 copies of enclosures

cc: Tom Cascio, FDEP Title V Section, w/o enclosures
James Packer, Mirant Corporation, w/o enclosures
Rick Waggoner, Mirant Corporation, w/o enclosures
L. Glenn Keeling, Mirant Corporation, w/o enclosures
Bruce Lobach, Shady Hills Generating Station, w/o enclosures

SHADY HILLS GENERATING STATION
UNIT 1 EMISSION TESTS SUMMARY



NOTES:

1. SITE ROADS TO BE HEAVY DUTY ASPHALT.
2. CONTAINMENT AREA LINER TO BE PETROGARD VIOR APPROVED EQUAL.
3. COORDINATES ARE BASED UPON PLANT GRID SYSTEM. ORIGIN AT TRUE SOUTHEAST PROPERTY CORNER AND IS PLANT N 5000, E 10000
4. TOTAL AREA OF SITE - 20.02 ACRES
5. ROAD COORDINATES TO CENTERLINE OF ROADS.
6. EXISTING TREES ALONG PERIMETER OF PROPERTY TO BE PROTECTED DURING CONSTRUCTION
7. EXISTING BARBED WIRE FENCES TO BE REMOVED.

NO	DATE	REVISION	BY	CK.	APPR.
3	31AUG2001	REVISED FUEL UNLOADING, ADD BALLAST PADS	MAK	WRC	JBS
2	27FEB2001	REVISED GRAVEL ROAD	MAK	WRC	JBS
1	19JAN2001	REVISED AS NOTED	MAK	WRC	JBS
0	27OCT2000	INITIAL ISSUE	MAK	WRC	JBS

DESIGNED BY M.A. KIM
CHECKED BY W.R. COOK
APPR. BY J.T. HUTTON
CLIENT APPR.

LOCKWOOD GREENE
A J.A. JONES COMPANY
ENGINEERING & CONSTRUCTION
Certificate: EB-0000384
250 Williams Street
Atlanta, GA 30303-1036

SHEET TITLE: OVERALL SITE PLAN

JOB NAME: SHADY HILLS POWER PROJECT

JOB NO. 010658.01
DATE 31-AUG-2001
FILENAME C0002000.DGN
REV. NO 3
SCALE 1" = 50'
DWG. NO. C-2000

EXECUTIVE SUMMARY

Coastal Air Consulting, Inc. (Coastal) performed emission testing at the Shady Hills Generating Station in Pasco County, Florida. Testing was performed to demonstrate compliance with conditions cited in Florida Department of Environmental Protection Permit No. PSD-FL-280, DEP Facility No. 1010373. The testing was completed on Unit 1 firing natural gas on January 10 and 11, and on Unit 1 firing distillate oil on January 14 and 15, 2002.

This unit is a General Electric stationary, combustion turbine (PG7241FA, Frame 7FA) operated in the simple cycle mode. The Frame 7FA gas turbine operates on natural gas in the dry low NO_x (DLN) mode. This unit is also equipped for water injection for NO_x control when firing distillate fuel oil.

Testing was completed at base load conditions while the unit fired natural gas and distillate oil. The parameters measured include carbon monoxide, nitrogen oxides, volatile organic compounds, flue gas moisture, opacity and flue gas volumetric flow rate (calculated). The results of the testing demonstrated that actual emissions are below all applicable air emissions permit limits. Test results (average of three runs) are summarized below:

Parameter	100% Load	Allowable
NOx, ppmvd, @ 15% O_2		
natural gas	7.5	9
distillate oil	39.1	42
NOx, lb/hr, ISO		
natural gas	48.5	64.1
distillate oil	309.5	351
CO, ppmvd		
natural gas	0.65	12
distillate oil	1.0	20
CO, lb/hr, ISO		
natural gas	2.2	42.5
distillate oil	3.20	71.4
VOCs, ppmvd		
natural gas	<0.1[a]	1.4
VOCs, ppmvw		
distillate oil	<0.1[a]	7
VOCs, lb/hr		
natural gas	<0.18	2.8
distillate oil	<0.18	16.2
SO_2, gr/100 scf, natural gas	0.0007	1
SO_2, % sulfur, distillate oil	0.0388	0.05
SO_2, lb/hr		
natural gas	0.294	5
distillate oil	80.71	98.7
Visible Emissions, %		
natural gas	0.0	10
distillate oil	0.0	10

[a]– Value is below detection limit

STATEMENT OF VALIDITY

Shady Hills Generation Station
Coastal Air Consulting Report
February 28, 2002

I hereby certify the information and data provided in this emissions test report for tests conducted at the Shady Hills Generating Station in Pasco County, Florida are true and correct, to the best of my knowledge.

Stephen C. Webb

Stephen C, Webb
President

Table of Contents

Tables

1.0 INTRODUCTION

Shady Hills Generating Station is located in Pasco County, Florida. This report summarizes the data collected during testing on Unit 1. The unit is a simple cycle General Electric stationary combustion turbine (PG7241FA, Frame 7FA). The Frame 7FA gas turbine operates on natural gas in the dry low NO_x (DLN) mode. This unit is also equipped for water injection for NOx control when firing distillate oil. This report summarizes results for testing when firing natural gas and distillate oil.

Coastal Air Consulting, Inc. was contracted by Lockwood Greene E & C to perform the initial compliance test demonstration.

1.1 Purpose and Objectives

The data collected during this testing will be used by Lockwood Greene E & C to demonstrate compliance with air emission permit requirements.

Table 1-1 provides a matrix of parameters, load conditions and purposes of the testing.

TABLE 1-1. Test Matrix and Purpose of Testing

Parameter (both fuels)	EPA Test Methods	100% Load
NOx	EPA M20	Permit
CO	EPA M10	Permit
VOC	EPA M25A	Permit
Moisture	EPA M4	Info
VE	EPA M9	Permit
O_2	EPA M3A	Info
CO_2	EPA M3A	Info
Stack Flowrate	EPA M19 calc.	Info

Three runs per 100% load condition; VOC – volatile organic compounds;
Permit – air permit requirement; Info – internal information or supporting other data requirements;
Natural gas sample collected during each test day and analyzed for composition (ultimate), specific gravity, and heating value.
Distillate oil sample collected during each test day and analyzed for composition (ultimate), specific gravity, and heating value.

1.2 Test Program Organization

The primary contacts for the test program were:

Lockwood Greene E &C Personnel
Robert Chalfant, Manager air quality services (404) 818-8325
James Riley, Project Engineer, (404) 818-8155
Don Dickerson, Environmental Project Manager, On-site contact, (706) 724-8225
Coastal Personnel
Stephen Webb, President/field team leader, (386) 943-9241
Robert Righter, Chemist, (386) 943-9241

1.3 Project Test Plan

Coastal followed the methodology and procedures cited in the document entitled "Air Emissions Performance Tests" for Shady Hills Power, dated October 4, 2001.

There were no significant deviations from the Test Plan. There were no significant data quality problems encountered during this testing. The original test plan called for on-line GC sample and analysis for methane and ethane. The total hydrocarbons measurements never exceeded the minimum detection limit, therefore the methane/ethane analysis was not necessary.

Performance testing for demonstration of compliance with emission limits in Permit No. PSD-FL-280 and 40 CFR 60 Subpart GG was conducted at base load conditions (nominal 100% capacity). This single operating load testing is consistent with the May 26, 2000 letter from U.S. EPA Region 4 to the Region 4 Air Division Directors addressing routine alternative testing procedures for combustion turbines (CTs) under NSPS. The EPA letter specifies that for CTs equipped with NOx CEMS, the monitors will provide credible evidence regarding the unit's compliance status on a continuous basis following the initial test, and level of compliance assurance provided in this case is sufficient to justify approval of requests that initial performance testing be allowed at a single operating load. The CTs are equipped with CEMS in accordance with the PSD permit and 40 CFR Part 75 requirements. A letter requesting approval of single operating load testing was submitted to and approval was confirmed with Mr. Joseph Kahn of the Florida DEP Emissions Monitoring Section.

1.4 Report Contents

The remainder of this Report is comprised of four Sections and Appendices. Section 2 contains a brief summary of the results in comparison to the compliance demonstration requirements. Section 3 provides a description of the procedures followed for the testing as specified in the Test Plan. Section 4 contains detailed summaries of emission testing results and associated quality control measures.

The Appendices contain all supporting documentation for the results presented in this report.

2.0 SUMMARY OF RESULTS

The emission tests for Unit 1 natural gas and Unit 1 distillate oil were conducted under the conditions specified in the Emission Test Plan dated October 4, 2001 that was previously prepared by Lockwood Greene E & C. There were no significant deviations from the standard test procedures set within the plan.

Results of three test runs are averaged and presented in Table 2-1 for comparison to the air permit emission limits. A more complete discussion of the results is provided in Section 4. All reported emissions are below the air construction permit emission limits and standards.

Table 2-1. Summary of Results

Parameter	100% Load	Allowable
NOx, ppmvd, @ 15% O_2		
natural gas	7.5	9
distillate oil	39.1	42
NOx, lb/hr, ISO		
natural gas	48.5	64.1
distillate oil	309.5	351
CO, ppmvd		
natural gas	0.65	12
distillate oil	1.0	20
CO, lb/hr, ISO		
natural gas	2.2	42.5
distillate oil	3.20	71.4
VOCs, ppmvd		
natural gas	<0.1[a]	1.4
VOCs, ppmvw		
distillate oil	<0.1[a]	7
VOCs, lb/hr		
natural gas	<0.18	2.8
distillate oil	<0.18	16.2
SO_2, gr/100 scf, natural gas	0.0007	1
SO_2, % sulfur, distillate oil	0.0388	0.05
SO_2, lb/hr		
natural gas	0.294	5
distillate oil	80.71	98.7
Visible Emissions, %		
natural gas	0.0	10
distillate oil	0.0	10

[a]– Value is below detection limit

3.0 TEST PROGRAM DESCRIPTION

Coastal configured a sampling/monitoring strategy consistent with the requirements cited in the Air Construction Permit No.PSD-FL-280, the associated emission limits and GE's air emission performance guarantees.

This subsection identifies the procedures that were followed to demonstrate compliance with the air permit emission limits and 40 CFR Part 60 Subpart GG New Source Performance Standards (NSPS), as applicable. All compliance testing was completed in strict accordance with the methods, as applicable. Manual testing according to EPA Reference Method 4 was included in this project.

Table 3-1 summarizes the monitoring procedures followed for the demonstration testing.

Table 3-1. Instrument Specifications

Analyte	Instrument/Principal	Range Specifications	Calibration Values
NO_x by EPA Method 20	Beckman Model 951A, Chemiluminscence	0-25 ppm (for gas) 0-60 ppm (for oil)	0, 5.18, 12.89, 23.00 0, 12.89, 27.12, 42.2
O_2 by EPA Method 3A	Servomex 1400 Paramagnetic	0-25 percent	0, 10.4, 21.98
CO_2 by EPA Method 3A	Servomex 1400 Infrared	0-20 percent	0, 10.4, 16.77
CO by EPA Method 10	TECO Model 48 CTL NDIR w/GFC	0-50 ppm	0, 15.44, 27.55, 45.4
VOCs by EPA Method 25A (for total unburned hydrocarbon)	California Analytical flame ionization detector (THC)	0-20 ppm for THC monitor	0, 6.02, 10.12, 17.07

The procedures for the measurements during this program were primarily instrumentation techniques using continuous emission monitors. Coastal's continuous emission monitoring system (CEMS) is housed inside a mobile laboratory.

Sample gas extracted from the source being monitored was first cleaned and dried before analysis (except total hydrocarbons). The gas was conditioned by passing through a heat-traced Teflon line into a condenser-style moisture removal system prior to analysis for NO_x, CO_2, O_2 and CO. The conditioning system cools the gas to approximately 35 °F and thereby condenses out most of the moisture in the sample. The system is operated with chilled condensers, which are

continuously drained thereby minimizing the possibility of scrubbing target compounds. The flow rate is monitored and controlled through a series of valves and rotometers.

A separate system was used for the total hydrocarbon monitoring. The sample gas was transported directly to the analyzer (unconditioned) through a heat-traced Teflon sample line.

Calibrations were performed with EPA Protocol 1 gases. The Protocol 1 gas certifications are included in the Appendices.

Output from each analyzer was compiled on a microprocessor controlled data acquisition system. One-minute averages were recorded and translated to a computer spreadsheet for further data reduction. All data were printed on site and stored electronically including at least one backup file.

The following subsections provide brief descriptions of the EPA Reference Methods and any technical concerns encountered during the test program. This section also contains information on the fuel analysis and manual moisture measurements that were performed.

3.1 NO_x by EPA Method 20

A Beckman Model 951A analyzer was used to measure NO_x. The operating principle of this instrument is a chemiluminiscent reaction in which ozone reacts with nitric oxide to form oxygen and nitrogen dioxide in an excited state. The excited NO_2 decays rapidly to the unexcited state, emitting a photon which is measured by a photomultiplier tube. The instrument measures total oxides of nitrogen (nitrogen oxide and nitrogen dioxide) by thermally converting nitrogen dioxide to nitrogen oxide in a separate reaction chamber prior to the multiplier tube.

Measurements were performed in accordance with 40 CFR Part 60, Appendix A, EPA Reference Method 20, *Determination of Nitrogen Oxides, Sulfur Dioxides and Diluent Emissions from Gas Turbines*. Three runs were completed at the 100% load condition.

A stratification test was performed as part of the preliminary measurements. Coastal completed a 48-point stratification check measuring and reporting results for oxygen. Coastal then selected the eight monitoring points that reported the lowest oxygen concentrations as the points for monitoring during the compliance tests. EPA Method 20 requires that each point be sampled for a minimum of 1 minute plus response time of the NO_x analyzer. All CEMS instrumentation reported a response time of less than one minute. Each of the selected eight points were monitored for 7.5 minutes to yield a 60-minute run.

Quality control checks specified in EPA Method 20 were performed. These checks include converter efficiency checks, response time checks, system calibrations and bias checks. Vendor data was provided for interference response checks. These data are reported in Appendix A.

3.2 CO by EPA Method 10

A TECO Model 48CTL trace analyzer was used for the CO monitoring. With this system, concentrations are detected using the nondispersive infrared (NDIR) gas filter correlation technique. Radiation from the infrared source is chopped and then passed through a gas filter alternating between CO and nitrogen due to rotation of the filter wheel. The radiation then passes through an interference filter and enters a multiple pass optical cell where absorption by the sample gas occurs. The CO gas filter produces a reference beam that cannot be further attenuated by CO in the sample cell. At the same time, the nitrogen gas filter produces a measuring beam that can be absorbed by CO in the cell. The chopped detector signal is modulated by the alternation between the two gas filters. The sample amplitude is related to the concentrations of CO in the sample cell.

Coastal followed the requirements of 40 CFR Part 60, Appendix A, EPA Reference Method 10, *Determination of Carbon Monoxide Emissions from Stationary Sources*. Three runs were completed at the appropriate load conditions concurrent with the NO_x measurements.

3.3 CO_2 and O_2 by EPA Method 3A

A Servomex 1400 analyzer was used for the oxygen monitoring. With this system, concentrations are detected using the paramagnetic principle. The analyzer evaluates the paramagnetic susceptibility of the sample gas using a magnetodynamic measuring cell. The response voltage is proportional to the oxygen concentration ratio.

An Servomex 1400 analyzer was used for the carbon dioxide monitoring. This analyzer emits a single beam of infrared radiation at dual wavelengths. The beam passes through a sample cell and radiation at the specific wavelengths is selectively absorbed by the carbon dioxide molecules. The intensity of radiation reaching the end of the sample cell is inversely proportional to the carbon dioxide concentration in the gas.

Coastal followed the requirements of 40 CFR Part 60, Appendix A, EPA Reference Method 3A, *Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources*. These measurements were made concurrently with all others (3 runs per test condition).

3.4 Total Hydrocarbons by EPA Method 25A

Coastal used a CAI Model 300 analyzer to perform these measurements. In this analyzer, the unconditioned (non-filtered, wet) flue gas enters the flame ionization detector (FID) and the hydrocarbons are combusted in a hydrogen flame. The ions and electrons formed enter an electrode gap, decrease the gas resistance, and permit a current flow in the external circuit. The resulting current is proportional to the instantaneous concentration of unburned hydrocarbons. The results were reported on a methane equivalent basis.

Coastal performed measurements for total hydrocarbons following 40 CFR Part 60, Appendix A, EPA Reference Method 25A *Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer*. Three runs were performed at the 100% load condition. The original test plan called for on-line GC sample and analysis for methane and ethane. The total hydrocarbons measurements never exceeded the minimum detection limit, therefore the methane/ethane analysis was not necessary. The mass emission rate was calculated using the minimum detection value.

3.5 Sampling and Analysis of Fuels (Natural Gas & Distillate Oil)

Natural gas samples were collected on January 10, 2002 and the distillate oil samples were collected January 14, 2002. The samples were shipped to Core Laboratories of Houston, TX for BTU and specific gravity analysis. Natural gas samples were analyzed according to the procedures outlined in Table 3-2. The oil analysis are located in Appendix K.

Table 3-2. Fuel Analysis Procedures

Parameter	Procedure	Collection Frequency
Specific Gravity	ASTM D 3588	Two samples collected at each unit; one analysis performed per unit.
Heating Value	ASTM D 3588	
Sulfur	ASTM D3246	

The data from the fuel sample analysis were used to calculate flue gas volumetric flow rate using procedures identified in EPA Reference Method 19 and to demonstrate compliance with fuel sulfur content and sulfur dioxide emission limits.

3.6 Stack Gas Volumetric Flow by EPA Method 19

Stack gas volumetric flow rate was calculated using the procedures cited in EPA Method 19. This Method establishes F-factors, which relate to the gas volume of the combustion products to the heat content of the fuel. Data from the fuel analysis was used to calculate oxygen based and carbon dioxide based F-factors. The oxygen-based F-factor was used with the measured fuel feed rates, fuel heating value and oxygen content of the stack gas to calculate the total volumetric flow rate of the stack gas. The CO_2 F-factor, carbon content of the natural gas, along with the fuel feed rate, fuel heating value and carbon dioxide content was used also to calculate stack volumetric flow rate.

3.7 Stack Gas Moisture by EPA Method 4

Moisture content was measured according to EPA Method 4 requirements. A known volume of flue gas was extracted through a series of preweighed/premeasured impingers (two impingers with water, one empty impinger and one silica gel impinger) to assess the mass of water collected. This mass, when compared against the known sample gas volume, was used to calculate flue gas moisture content. The flue gas moisture content was determined for each test condition. Three 30-minute runs were performed during each test condition concurrent with the CEMS measurements. This data was used to convert the measured hydrocarbon concentrations from a wet basis to a dry basis.

3.8 Measurement of Ambient Conditions

Coastal took measurements of barometric pressure (on site barometer) and absolute humidity (sling psychrometer to provide dry bulb and wet bulb temperatures, °F). Measurement frequency was once per run during each condition.

3.9 Process Data

Facility personnel were responsible for collection of all pertinent process data. A hard copy of this data was printed on the Mark VI emission test data display screen at each load stabilization. Data was accumulated and stored on disk during the test runs. Process parameters of interest included:

- Mean turbine exhaust temperature (TTXM),°F
- Fuel flow (FQG) lb/sec (Natural Gas); FQLM1 (Distillate Oil)
- Compressor inlet temperature (CT1F1, CT1F2, CTIM), °F

- Specific Humidity (CMHUM), lb H_2O/lb dry air
- Generator Output (DWATT), MW
- Compressor discharge pressure (CPD), psig
- Inlet Guide Vane Angle (CSGV), degrees

4.0 TEST RESULTS

4.1 Test Narrative

Air emission permit compliance testing was completed on January 10 and 11 for Unit 1 natural gas; and January 14 and 15, 2002 for Unit 1 distillate oil.

Testing was completed using CEMS procedures and manual test procedures (moisture). All reported results are supported with data contained in the Appendices to this document.

Coastal completed a stack traverse in accordance with EPA Method 20 requirements while the unit was operating near 50 percent of full load. A total of 48 points were monitored (12 points from each of 4 ports) for oxygen content to determine the presence of stratification. The traverse verified the absence of stratification in the stack for both Units.

During the test runs using the CEMS procedures, each sample point was monitored for seven and one half minutes at each of eight selected representative sample points to yield a total of 60 minutes per sample run. Test Runs for moisture content were 30-minutes in duration. The sample periods are consistent with the Emission Test Plan and the requirements of EPA Reference Method 20.

Three runs were performed at 100 percent of full load. Only air emission permit related parameters are reported in this document.

Table 4-1 summarizes test times and operating conditions.

Table 4-1. Air Emission Permit Limit Compliance Test Sequence
Unit 1 When Firing Natural Gas and Unit 1 When Firing Distillate Oil

Load	Run Number	Date/Time	Comment
Unit 1 when firing natural gas			
50% Load	O2 Traverse	1/10/02, 0957-1242	approximately 85 MW
100% Load	Run 1 Run 2 Run 3	1/10/02, 1500-1600 1/10/02, 1650-1750 1/10/02, 1818-1918	
Unit 1 when firing distillate oil			
50% Load	O2 Traverse	1/14/02, 1830-2042	approximately 85 MW
100% Load	Run 1 Run 2 Run 3	1/14/02, 2314-0014 1/15/02, 0046-0146 1/15/02, 0159-0259	

Table 4-2 summarize the results of the air emission testing on a per run basis for Unit 1 firing natural gas. Table 4-3 present the results for testing on Unit 1 firing distillate oil.

Table 4-2. Emission Summary Table for Shady Hills Generating Station, Pasco County, FL - Unit 1
Approximately 100% Base Load Conditions on Natural Gas

Test Identification					
Test Period	--	1	2	3	Average
Test Condition	load level, %	100	100	100	
Sampling Location	--	stack	stack	stack	
Date	--	10-Jan-02	10-Jan-02	10-Jan-02	
Test Time (start-stop)	--	1500-1600	1650-1750	1818-1918	
Ambient Conditions					
Barometric Pressure	In. Hg	30.19	30.19	30.19	30.19
Ambient Temperature	°F	70	68	65	67.7
Wet Bulb Temperature	°F	56	56	56	56.0
Absolute Humidity	lb water/lb dry air	0.00610	0.00656	0.00726	0.00664
Turbine Operating Conditions					
Mean Turbine Exhaust Temp., TTXM	°F	1098.8	1095.6	1091.0	1095.1
Fuel Flow, FQG	lb/sec	20.45	20.69	20.92	20.69
Compressor Inlet Temperature, CTIM	°F	67.6	63.3	57.2	62.7
Specific Humidity, CMHUM	lb/lb	0.01560	0.00830	0.00490	0.00960
Inlet Guide Vane Angle. CSGV	degrees	86.0	85.9	86.0	85.9
Generator Output, DWATT	mw	170.3	172.9	176.0	173.1
Compressor Discharge Pressure, CPD	psig	218.0	220.1	222.5	220.2
Exhaust Gas Conditions					
Volumetric Flow, M-19, F_d	dscfm	718,052	726,479	737,663	727,398
Volumetric Flow, M-19, F_c	dscfm	768,093	775,062	781,621	774,925
Moisture	%V	8.4	8.0	7.9	8.1
O_2	%	13.78	13.78	13.81	13.79
CO_2	%	3.79	3.80	3.81	3.80
NO_x	ppmvd	8.84	9.59	8.70	9.04
Exhaust Emissions					
Visible Emissions	%	0.0	0.0	0.0	0.0
SO_2	lb/hr	0.294	0.294	0.294	0.294
SO_2	gr/100 scf	0.0007	0.0007	0.0007	0.0007
CO	ppmvd	0.55	0.44	0.95	0.65
CO	lb/hr,ISO	1.85	1.44	3.19	2.16
CO	lb/hr	1.79	1.39	3.12	2.1
VOC	ppmvd	< 0.1	< 0.1	< 0.1	< 0.1
VOC	lb/hr	<0.18	<0.18	<0.18	<0.18
NO_x	ppmvd @ 15% O_2	7.3	8.0	7.2	7.5
NO_x	lb/hr, ISO	47.0	51.5	47.0	48.5
NO_x	lb/hr	45.5	49.9	46.0	47.1

Table 4-3. Emission Summary Table for Shady Hills Generating Station, Pasco County, FL - Unit 1
Approximately 100% Base Load Conditions on Distillate Oil

Test Identification					
Test Period	--	1	2	3	Average
Test Condition	load level, %	100	100	100	
Sampling Location	--	stack	stack	stack	
Date	--	14-Jan-02	15-Jan-02	15-Jan-02	
Test Time (start-stop)	--	2314-0014	0046-0146	0159-0259	
Ambient Conditions					
Barometric Pressure	In. Hg	29.90	29.90	29.90	29.90
Ambient Temperature	°F	64	64	61	63.0
Wet Bulb Temperature	°F	63	63	63	63.0
Absolute Humidity	lb water/lb dry air	0.01189	0.01189	0.01189	0.01189
Turbine Operating Conditions					
Mean Turbine Exhaust Temp., TTXM	°F	1141.6	1140.7	1140.7	1141.1
Fuel Flow, FQLM1	lb/sec	28.77	28.80	28.85	28.81
Compressor Inlet Temperature, CTIM	°F	68.0	67.1	66.2	67.1
Specific Humidity, CMHUM	lb/lb	0.00980	0.00940	0.00910	0.00943
Inlet Guide Vane Angle. CSGV	degrees	86.0	85.9	85.9	85.9
Generator Output, DWATT	mw	191.0	191.1	191.6	191.2
Compressor Discharge Pressure, CPD	psig	224.7	224.7	225.2	224.9
Exhaust Gas Conditions					
Volumetric Flow, M-19, F_d	dscfm	727,696	727,637	732,191	729,174
Volumetric Flow, M-19, F_c	dscfm	765,092	768,313	768,431	767,279
Moisture	%V	12.3	11.8	12.2	12.1
O_2	%	12.01	12.00	12.04	12.02
CO_2	%	6.34	6.32	6.33	6.33
NO_x	ppmvd	58.35	58.97	59.30	58.87
Exhaust Emissions					
Visible Emissions	%	0.0	0.0	0.0	0.0
SO_2	lb/hr	80.7	80.7	80.7	80.7
SO_2	%sulfur	0.0388	0.0388	0.0388	0.0388
CO	ppmvd	0.90	1.05	0.95	0.97
CO	lb/hr, ISO	3.0	3.47	3.13	3.20
CO	lb/hr	2.97	3.43	3.09	3.17
VOC	ppmvw	< 0.1	0.1	< 0.1	< 0.1
VOC	lb/hr	<0.18	0.18	<0.18	<0.18
NO_x	ppmvd @ 15% O_2	38.7	39.1	39.5	39.1
NO_x	lb/hr, ISO	307.0	310.2	311.4	309.5
NO_x	lb/hr	304.2	307.4	311.1	307.6

4.2 Quality Control Procedures and Results

Specific quality assurance and quality control (QA/QC) procedures were followed during this test program to ensure the production of useful and valid data. The QA/QC checks and procedures described in this section are an integral part of the overall sampling scheme. The acceptance criteria, control limits and corrective action that were followed are summarized in Table 4-4. All measurements were within cited control limits. Supporting documentation for each of these quality control measures are provided in the Appendices.

4.2.1 Continuous Emission Monitors Data Quality

Continuous monitoring for NO_x, CO, O_2, and CO_2 was performed using the instruments discussed in Section 3. Quality control procedures for all instruments are similar. The primary control check for precision of the continuous monitors was the analysis of control standards. The control standards were used to calibrate the instruments at the beginning and end of each day and to check instrument drift as required after each run. EPA Protocol 1 gases were used.

Calibration and Linearity Check

Analyzer calibration was performed at least once each test day. Analyzer response for NO_x, VOC and CO was set using low, mid and high level span gases. Analyzer response for O_2, and CO_2 was set using the zero, mid and high level span gases. Subsequent response to the calibration gases were within the limits shown in Table 4-4.

Drift Checks

At the beginning and end of each test run, zero and upscale gases were introduced into the instruments as required by the reference methods. Drift for each test was determined using the results of the pre-test and post-test calibration checks.

Other QC Checks

Records of daily leak checks, sample line bias checks and response time checks were performed according to the specifications in the reference methods and listed in Table 3-1. Results of each of these checks are provided in Appendix A. A test of the NO_2 to NO conversion efficiency of the NO_x analyzer was performed according to the specifications in EPA Method 20.

Table 4-4. Quality Control Checks

Criteria	Control Limits	Corrective Action
Instrument Measurements: General		
Line Leak Check	<0.5% O_2	Locate & repair leak, recheck
Manifold Leak Check	<0.5% O_2	Locate & repair leak, recheck
Instrument Measurements: NO_x, O_2, and CO_2		
Calibration Error (low & high level)	±2.0% of span	Adjust instrument, recalibrate
Drift Between Runs (zero & mid-level)	±2.0% of span	Adjust data for drift
Response Time	Less than 30 seconds	Increase sample flow rate
NO_2 to NO Conv. Efficiency	>90% conversion	Replace converter, recheck
Instrument Measurements: CO		
Calibration Error (low & mid-level)	±2.0% of full scale	Adjust instrument, recalibrate
Drift (zero, mid & high-level)	±10.0% of span in 8 hrs.	Adjust data for drift
Response time	Less than 30 seconds	Increase sample flow rate
Instrument Measurements: VOC		
Calibration Error (low & mid-level)	±5.0% of gas value	Adjust instrument, recalibrate
Drift Between Runs (zero & mid-level)	±3.0% of span	Adjust data for drift
Response Time	None	Record response time
Manual Sampling		
Final Leak Rate	≤0.02 acfm or 4% of sampling rate whichever is less	Adjust sample volume
Dry Gas Meter Calibration	Post average factor (g) agree ±5% of pre-factor	Adjust sample volumes using the g that gives smallest volume
Indiv. Correction Factors (Y_i)	Agree within 2% of average factor	Redo correction factor
Average Correction Factor	1.00 ±1%	Adjust the dry gas meter and recalibrate
Intermediate Dry Gas Meter	Calibrated every 6 months against EPA standard	--

4.2.2 Quality Control Procedures for Manual Sampling

Gas Sample Volume Determination (by EPA Method 4)

The raw volume indicated by the dry gas meter was corrected to a standard volume, using measurements of the actual meter pressure and temperature and the meter calibration factor. The meter calibration factor was established prior to the test using a set of calibration orifices. Pre-test and post-test leak checks were performed to ensure no leakage of ambient air into the system thereby biasing the stack gas sample volume determination.

Moisture Determination QA/QC

The moisture content of the gas stream was determined using EPA Method 4. The moisture value was used to correct the wet VOC measurements to a dry basis. In order to assure good moisture data, several quality control procedures were followed. The balance used for weighing impingers was electronically checked for accuracy and with standard calibration weights periodically. The indicating silica gel in the moisture trains was checked for saturation after each run and changed if necessary. The impinger exit gas temperature was monitored during the run, and sufficient ice was maintained in the impinger bucket to keep the temperature lower than 68°F.

Sample Custody Procedures

Custody procedures for fuel samples included careful documentation of sample collection, and the use of chain-of-custody records for sample transportation. The sample containers were each tagged with a unique sample identification number. This number appeared on the chain-of-custody records, and was carried through the laboratory to appear on the final analytical reports. The Field Team Leader was responsible for ensuring that proper custody and documentation procedures are followed for sampling and analysis.

Data gathered at the sampling locations, including sampling times and any special conditions associated with specific samples, was recorded in the test log. Prepared data sheets were used to record ambient data. Required sampling intervals and actual sampling times were clearly noted on the data sheets. Electronically recorded data was downloaded daily from the computer hard drive to floppy disks for backup.

4.2.3 Data Reduction, Validation, and Reporting

All data and calculations for flow rates and moisture concentrations were made using a computer spreadsheet. Calculated data was validated by an independent check. A predetermined input data set with known expected output values was entered to each spreadsheet to confirm proper function. All hand calculations were spot checked for accuracy and completeness on-site by the Field Engineer.

All measurement data were validated based on the following criteria:

- Stable process conditions during sampling and testing;
- Acceptable sample collection procedures;
- Consistency with other expected results; and
- Adherence to prescribed QC procedures.

SHADY HILLS GENERATING STATION
UNIT 2 EMISSION TESTS SUMMARY

EXECUTIVE SUMMARY

Coastal Air Consulting, Inc. (Coastal) performed emission testing at the Shady Hills Generating Station in Pasco County, Florida. Testing was performed to demonstrate compliance with conditions cited in Florida Department of Environmental Protection Permit No. PSD-FL-280, DEP Facility No. 1010373. The testing was completed on Unit 2 firing natural gas on January 16, and on Unit 2 firing distillate oil on January 28, 2002.

This unit is a General Electric stationary, combustion turbine (PG7241FA, Frame 7FA) operated in the simple cycle mode. The Frame 7FA gas turbine operates on natural gas in the dry low NO_x (DLN) mode. This unit is also equipped for water injection for NO_x control when firing distillate fuel oil.

Testing was completed at base load conditions while the unit fired natural gas and distillate oil. The parameters measured include carbon monoxide, nitrogen oxides, volatile organic compounds, flue gas moisture, opacity and flue gas volumetric flow rate (calculated). The results of the testing demonstrated that actual emissions are below all applicable air emissions permit limits. Test results (average of three runs) are summarized below:

Parameter	100% Load	Allowable
NOx, ppmvd, @ 15% O_2		
natural gas	7.4	9
distillate oil	38.2	42
NOx, lb/hr, ISO		
natural gas	50.0	64.1
distillate oil	313.5	351
CO, ppmvd		
natural gas	0.13	12
distillate oil	0.55	20
CO, lb/hr, ISO		
natural gas	0.54	42.5
distillate oil	2.83	71.4
VOCs, ppmvd		
natural gas	<0.1[a]	1.4
VOCs, ppmvw		
distillate oil	<0.1[a]	7
VOCs, lb/hr		
natural gas	<0.18	2.8
distillate oil	<0.18	16.2
SO_2, gr/100 scf, natural gas	0.0007	1
SO_2, % sulfur, distillate oil	0.0438	0.05
SO_2, lb/hr		
natural gas	0.311	5
distillate oil	87.9	98.7
Visible Emissions, %		
natural gas	0.0	10
distillate oil	0.0	10

[a] – Value is below detection limit

STATEMENT OF VALIDITY

Shady Hills Generation Station
Coastal Air Consulting Report
March 7, 2002

I hereby certify the information and data provided in this emissions test report for tests conducted at the Shady Hills Generating Station in Pasco County, Florida are true and correct, to the best of my knowledge.

Stephen C. Webb
President

Table of Contents

Tables

1.0 INTRODUCTION

Shady Hills Generating Station is located in Pasco County, Florida. This report summarizes the data collected during testing on Unit 2. The unit is a simple cycle General Electric stationary combustion turbine (PG7241FA, Frame 7FA). The Frame 7FA gas turbine operates on natural gas in the dry low NO_x (DLN) mode. This unit is also equipped for water injection for NOx control when firing distillate oil. This report summarizes results for testing when firing natural gas and distillate oil.

Coastal Air Consulting, Inc. was contracted by Lockwood Greene E & C to perform the initial compliance test demonstration.

1.1 Purpose and Objectives

The data collected during this testing will be used by Lockwood Greene E & C to demonstrate compliance with air emission permit requirements.

Table 1-1 provides a matrix of parameters, load conditions and purposes of the testing.

TABLE 1-1. Test Matrix and Purpose of Testing

Parameter (both fuels)	EPA Test Methods	100% Load
NOx	EPA M20	Permit
CO	EPA M10	Permit
VOC	EPA M25A	Permit
Moisture	EPA M4	Info
VE	EPA M9	Permit
O_2	EPA M3A	Info
CO_2	EPA M3A	Info
Stack Flowrate	EPA M19 calc.	Info

Three runs per 100% load condition; VOC – volatile organic compounds;
Permit – air permit requirement; Info – internal information or supporting other data requirements;
Natural gas sample collected during each test day and analyzed for composition (ultimate), specific gravity, and heating value.
Distillate oil sample collected during each test day and analyzed for composition (ultimate), specific gravity, and hearing value.

1.2 Test Program Organization

The primary contacts for the test program were:

Lockwood Greene E &C Personnel
Robert Chalfant, Manager air quality services (404) 818-8325
James Riley, Project Engineer, (404) 818-8155
Don Dickerson, Environmental Project Manager, On-site contact, (706) 724-8225
Coastal Personnel
Stephen Webb, President/field team leader, (386) 943-9241
Robert Righter, Chemist, (386) 943-9241

1.3 Project Test Plan

Coastal followed the methodology and procedures cited in the document entitled "Air Emissions Performance Tests" for Shady Hills Power, dated October 4, 2001.

There were no significant deviations from the Test Plan. There was no significant data quality problems encountered during this testing. The original test plan called for on-line GC sample and analysis for methane and ethane. The total hydrocarbons measurements never exceeded the minimum detection limit therefore the methane/ethane analysis was not necessary.

Performance testing for demonstration of compliance with emission limits in Permit No. PSD-FL-280 and 40 CFR 60 Subpart GG was conducted at base load conditions (nominal 100% capacity). This single operating load testing is consistent with the May 26, 2000 letter from U.S. EPA Region 4 to the Region 4 Air Division Directors addressing routine alternative testing procedures for combustion turbines (CTs) under NSPS. The EPA letter specifies that for CTs equipped with NOx CEMS, the monitors will provide credible evidence regarding the unit's compliance status on a continuous basis following the initial test, and level of compliance assurance provided in this case is sufficient to justify approval of requests that initial performance testing be allowed at a single operating load. The CTs are equipped with CEMS in accordance with the PSD permit and 40 CFR Part 75 requirements. A letter requesting approval of single operating load testing was submitted to and approval was confirmed with Mr. Joseph Kahn of the Florida DEP Emissions Monitoring Section.

1.4 Report Contents

The remainder of this Report is comprised of four Sections and Appendices. Section 2 contains a brief summary of the results in comparison to the compliance demonstration requirements. Section 3 provides a description of the procedures followed for the testing as specified in the Test Plan. Section 4 contains detailed summaries of emission testing results and associated quality control measures.

The Appendices contain all supporting documentation for the results presented in this report.

2.0 SUMMARY OF RESULTS

The emission tests for Unit 2 natural gas and Unit 2 distillate oil were conducted under the conditions specified in the Emission Test Plan dated October 4, 2001 that was previously prepared by Lockwood Greene E & C. There were no significant deviations from the standard test procedures set within the plan.

Results of three test runs are averaged and presented in Table 2-1 for comparison to the air permit emission limits. A more complete discussion of the results is provided in Section 4. All reported emissions are below the air construction permit emission limits and standards.

Table 2-1. Summary of Results

Parameter	100% Load	Allowable
NOx, ppmvd, @ 15% O_2		
natural gas	7.4	9
distillate oil	38.2	42
NOx, lb/hr, ISO		
natural gas	50.0	64.1
distillate oil	313.5	351
CO, ppmvd		
natural gas	0.13	12
distillate oil	0.55	20
CO, lb/hr, ISO		
natural gas	0.54	42.5
distillate oil	2.83	71.4
VOCs, ppmvd		
natural gas	<0.1[a]	1.4
VOCs, ppmvw		
distillate oil	<0.1[a]	7
VOCs, lb/hr		
natural gas	<0.18	2.8
distillate oil	<0.18	16.2
SO_2, gr/100 scf, natural gas	0.0007	1
SO_2, % sulfur, distillate oil	0.0438	0.05
SO_2, lb/hr		
natural gas	0.311	5
distillate oil	87.9	98.7
Visible Emissions, %		
natural gas	0.0	10
distillate oil	0.0	10

[a]– Value is below detection limit

3.0 TEST PROGRAM DESCRIPTION

Coastal configured a sampling/monitoring strategy consistent with the requirements cited in the Air Construction Permit No.PSD-FL-280, the associated emission limits and GE's air emission performance guarantees.

This subsection identifies the procedures that were followed to demonstrate compliance with air permit emission limits and 40 CFR Part 60 Subpart GG New Source Performance Standards (NSPS), as applicable. All compliance testing was completed in strict accordance with the methods, as applicable. Manual testing according to EPA Reference Method 4 was included in this project.

Table 3-1 summarizes the monitoring procedures followed for the demonstration testing.

Table 3-1. Instrument Specifications

Analyte	Instrument/Principal	Range Specifications	Calibration Values
NO_x by EPA Method 20	Beckman Model 951A, Chemiluminscence	0-25 ppm (for gas) 0-100 ppm (for oil)	0, 5.18, 12.89, 23.00 0, 27.12, 42.2,85.7
O_2 by EPA Method 3A	Servomex 1400 Paramagnetic	0-25 percent	0, 12.94, 21.98
CO_2 by EPA Method 3A	Servomex 1400 Infrared	0-20 percent	0, 13.02, 16.77
CO by EPA Method 10	TECO Model 48 CTL NDIR w/GFC	0-50 ppm	0, 15.44, 27.55, 45.4
VOCs by EPA Method 25A (for total unburned hydrocarbon)	California Analytical flame ionization detector (THC)	0-20 ppm for THC monitor	0, 6.02, 10.12, 17.07

The procedures for the measurements during this program were primarily instrumentation techniques using continuous emission monitors. Coastal's continuous emission monitoring system (CEMS) is housed inside a mobile laboratory.

Sample gas extracted from the source being monitored was first cleaned and dried before analysis (except total hydrocarbons). The gas was conditioned by passing through a heat-traced Teflon line into a condenser-style moisture removal system prior to analysis for NO_x, CO_2, O_2 and CO. The conditioning system cools the gas to approximately 35 °F and thereby condenses out most of the moisture in the sample. The system is operated with chilled condensers, which are

continuously drained thereby minimizing the possibility of scrubbing target compounds. The flow rate is monitored and controlled through a series of valves and rotometers.

A separate system was used for the total hydrocarbon monitoring. The sample gas was transported directly to the analyzer (unconditioned) through a heat-traced Teflon sample line.

Calibrations were performed with EPA Protocol 1 gases. The Protocol 1 gas certifications are included in the Appendices.

Output from each analyzer was compiled on a microprocessor controlled data acquisition system. One-minute averages were recorded and translated to a computer spreadsheet for further data reduction. All data were printed on site and stored electronically including at least one backup file.

The following subsections provide brief descriptions of the EPA Reference Methods and any technical concerns encountered during the test program. This section also contains information on the fuel analysis and manual moisture measurements that were performed.

3.1 NO_x by EPA Method 20

A Beckman Model 951A analyzer was used to measure NO_x. The operating principle of this instrument is a chemiluminiscent reaction in which ozone reacts with nitric oxide to form oxygen and nitrogen dioxide in an excited state. The excited NO_2 decays rapidly to the unexcited state, emitting a photon that is measured by a photomultiplier tube. The instrument measures total oxides of nitrogen (nitrogen oxide and nitrogen dioxide) by thermally converting nitrogen dioxide to nitrogen oxide in a separate reaction chamber prior to the multiplier tube.

Measurements were performed in accordance with 40 CFR Part 60, Appendix A, EPA Reference Method 20, *Determination of Nitrogen Oxides, Sulfur Dioxides and Diluent Emissions from Gas Turbines*. Three runs were completed at the 100% load condition.

A stratification test was performed as part of the preliminary measurements. Coastal completed a 48-point stratification check measuring and reporting results for oxygen. Coastal then selected the eight monitoring points that reported the lowest oxygen concentrations as the points for monitoring during the compliance tests. EPA Method 20 requires that each point be sampled for a minimum of 1 minute plus response time of the NO_x analyzer. All CEMS instrumentation reported a response time of less than one minute. Each of the selected eight points were monitored for 7.5 minutes to yield a 60-minute run.

Quality control checks specified in EPA Method 20 were performed. These checks include converter efficiency checks, system calibrations and bias checks. This data is reported in Appendix A.

3.2 CO by EPA Method 10

A TECO Model 48CTL trace analyzer was used for the CO monitoring. With this system, concentrations are detected using the nondispersive infrared (NDIR) gas filter correlation technique. Radiation from the infrared source is chopped and then passed through a gas filter alternating between CO and nitrogen due to rotation of the filter wheel. The radiation then passes through an interference filter and enters a multiple pass optical cell where absorption by the sample gas occurs. The CO gas filter produces a reference beam that cannot be further attenuated by CO in the sample cell. At the same time, the nitrogen gas filter produces a measuring beam that can be absorbed by CO in the cell. The chopped detector signal is modulated by the alternation between the two gas filters. The sample amplitude is related to the concentrations of CO in the sample cell.

Coastal followed the requirements of 40 CFR Part 60, Appendix A, EPA Reference Method 10, *Determination of Carbon Monoxide Emissions from Stationary Sources*. Three runs were completed at the 100% load condition.

3.3 CO_2 and O_2 by EPA Method 3A

A Servomex 1400 analyzer was used for the oxygen monitoring. With this system, concentrations are detected using the paramagnetic principle. The analyzer evaluates the paramagnetic susceptibility of the sample gas using a magnetodynamic measuring cell. The response voltage is proportional to the oxygen concentration ratio.

An Servomex 1400 analyzer was used for the carbon dioxide monitoring. This analyzer emits a single beam of infrared radiation at dual wavelengths. The beam passes through a sample cell and radiation at the specific wavelengths is selectively absorbed by the carbon dioxide molecules. The intensity of radiation reaching the end of the sample cell is inversely proportional to the carbon dioxide concentration in the gas.

Coastal followed the requirements of 40 CFR Part 60, Appendix A, EPA Reference Method 3A, *Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources*. These measurements were made concurrently with all others.

3.4 Total Hydrocarbons by EPA Method 25A

Coastal used a CAI Model 300 analyzer to perform these measurements. In this analyzer, the unconditioned (non-filtered, wet) flue gas enters the flame ionization detector (FID) and the hydrocarbons are combusted in a hydrogen flame. The ions and electrons formed enter an electrode gap, decrease the gas resistance, and permit a current flow in the external circuit. The resulting current is proportional to the instantaneous concentration of unburned hydrocarbons. The results were reported on a methane equivalent basis.

Coastal performed measurements for total hydrocarbons following 40 CFR Part 60, Appendix A, EPA Reference Method 25A *Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer*. Three runs were performed at the 100% load condition. The original test plan called for on-line GC sample and analysis for methane and ethane. The total hydrocarbons measurements never exceeded the minimum detection limit therefore the methane/ethane analysis was not necessary. The mass emission rate was calculated using the minimum detection value.

3.5 Sampling and Analysis of Fuels (Natural Gas & Distillate Oil)

Natural gas samples were collected on January 16, 2002 and the distillate oil samples were collected January 28, 2002. The natural gas samples were shipped to Core Laboratories of Houston, TX for BTU and specific gravity analysis. Natural gas samples were analyzed according to the procedures outlined in Table 3-2. The oil samples were shipped to Intertek Testing Services of Tampa FL, the analysis is located in Appendix K.

Table 3-2. Fuel Analysis Procedures

Parameter	Procedure	Collection Frequency
Specific Gravity	ASTM D 3588	Two samples collected at each unit; one analysis performed per unit.
Heating Value	ASTM D 3588	
Sulfur	ASTM D3246	

The data from the fuel sample analysis were used to calculate flue gas volumetric flow rate using procedures identified in EPA Reference Method 19 and to demonstrate compliance with fuel sulfur content and sulfur dioxide emission limits.

3.6 Stack Gas Volumetric Flow by EPA Method 19

Stack gas volumetric flow rate was calculated using the procedures cited in EPA Method 19. This Method establishes F-factors, which relate to the gas volume of the combustion products to the heat content of the fuel. Data from the fuel analysis was used to calculate oxygen based and carbon dioxide based F-factors. The oxygen-based F-factor was used with the measured fuel feed rates, fuel heating value and oxygen content of the stack gas to calculate the total volumetric flow rate of the stack gas. The CO_2 F-factor, carbon content of the natural gas, along with the fuel feed rate, fuel heating value and carbon dioxide content was used also to calculate stack volumetric flow rate.

3.7 Stack Gas Moisture by EPA Method 4

Moisture content was measured according to EPA Method 4 requirements. A known volume of flue gas was extracted through a series of preweighed/premeasured impingers (two impingers with water, one empty impinger and one silica gel impinger) to assess the mass of water collected. This mass, when compared against the known sample gas volume, was used to calculate flue gas moisture content. The flue gas moisture content was determined for each test condition. Three 30-minute runs were performed during each test condition concurrent with the CEMS measurements. This data was used to convert the measured hydrocarbon concentrations from a wet basis to a dry basis.

3.8 Measurement of Ambient Conditions

Coastal took measurements of barometric pressure (on site barometer) and absolute humidity (sling psychrometer to provide dry bulb and wet bulb temperatures, °F). Measurement frequency was once per run during each condition.

3.9 Process Data

Facility personnel were responsible for collection of all pertinent process data. A hard copy of this data was printed on the Mark VI emission test data display screen at each load stabilization. Data was accumulated and stored on disk during the test runs. Process parameters of interest included:

- Mean turbine exhaust temperature (TTXM),°F
- Fuel flow (FQG) lb/sec (Natural Gas); FQLM1 (Distillate Oil)
- Compressor inlet temperature (CT1F1, CT1F2, CTIM), °F

- Specific Humidity (CMHUM), lb H_2O/lb dry air
- Generator Output (DWATT), MW
- Compressor discharge pressure (CPD), psig
- Inlet Guide Vane Angle (CSGV), degrees

4.0 TEST RESULTS

4.1 Test Narrative

Air emission permit compliance testing was completed on January 16 for Unit 2 natural gas; and January 28, 2002 for Unit 2 distillate oil.

Testing was completed using CEMS procedures and manual test procedures (moisture). All reported results are supported with data contained in the Appendices to this document.

Coastal completed a stack traverse in accordance with EPA Method 20 requirements while the unit was operating near 50 percent of full load. A total of 48 points were monitored (12 points from each of 4 ports) for oxygen content to determine the presence of stratification. The traverse verified the absence of stratification in the stack for both Units.

During the test runs using the CEMS procedures, each sample point was monitored for seven and one half minutes at each of eight selected representative sample points to yield a total of 60 minutes per sample run. Test Runs for moisture content were 30-minutes in duration. The sample periods are consistent with the Emission Test Plan and the requirements of EPA Reference Method 20.

Three runs were performed at 100 percent of full load. Only air emission permit related parameters are reported in this document.

Table 4-1 summarizes test times and operating conditions.

Table 4-1. Air Emission Permit Limit Compliance Test Sequence
Unit 1 When Firing Natural Gas and Unit 2 When Firing Distillate Oil

Load	Run Number	Date/Time	Comment
Unit 1 when firing natural gas			
50% Load	O2 Traverse	1/15/02, 1900-2106	approximately 85 MW
100% Load	Run 1	1/16/02, 1145-1245	
	Run 2	1/16/02, 1307-1407	
	Run 3	1/16/02, 1431-1531	
Unit 1 when firing distillate oil			
50% Load	O2 Traverse	1/28/02, 1830-2042	approximately 85 MW
100% Load	Run 1	1/28/02, 1433-1533	
	Run 2	1/28/02, 1553-1653	
	Run 3	1/28/02, 1715-1815	

Table 4-2 summarize the results of the air emission testing on a per run basis for Unit 2 firing natural gas. Table 4-3 present the results for testing on Unit 2 firing distillate oil.

Table 4-2. Emission Summary Table for Shady Hills Generating Station, Pasco County, FL - Unit 2
Approximately 100% Base Load Conditions on Natural Gas

Test Identification					
Test Period	--	1	2	3	Average
Test Condition	load level, %	100	100	100	
Sampling Location	--	stack	stack	stack	
Date	--	16-Jan-02	16-Jan-02	16-Jan-02	
Test Time (start-stop)	--	1145-1245	1307-1407	1431-1531	
Ambient Conditions					
Barometric Pressure	In. Hg	30.14	30.14	30.14	30.14
Ambient Temperature	°F	70	73	76	73.0
Wet Bulb Temperature	°F	59	59	59	59.0
Absolute Humidity	lb water/lb dry air	0.00787	0.00718	0.00648	0.00718
Turbine Operating Conditions					
Mean Turbine Exhaust Temp., TTXM	°F	1090.6	1091.5	1091.3	1091.1
Fuel Flow, FQG	lb/sec	21.59	21.56	21.43	21.53
Compressor Inlet Temperature, CTIM	°F	54.1	55.0	56.5	55.2
Specific Humidity, CMHUM	lb/lb	0.01080	0.01070	0.01080	0.01077
Inlet Guide Vane Angle, CSGV	Degrees	86.0	86.0	86.0	86.0
Generator Output, DWATT	Mw	178.4	177.6	176.7	177.6
Compressor Discharge Pressure, CPD	psig	224.0	223.3	223.2	223.5
Exhaust Gas Conditions					
Volumetric Flow, M-19, F_d	dscfm	746,821	743,726	736,196	742,248
Volumetric Flow, M-19, F_c	dscfm	798,836	799,809	801,262	799,969
Moisture	%V	7.9	7.7	8.3	8.0
O_2	%	13.67	13.65	13.62	13.65
CO_2	%	3.84	3.83	3.80	3.82
NO_x	ppmvd	9.34	9.24	8.82	9.13
Exhaust Emissions					
Visible Emissions	%	0.0	0.0	0.0	0.0
SO_2	lb/hr	0.311	0.311	0.311	0.311
SO_2	gr/100 scf	0.0007	0.0007	0.0007	0.0007
CO	ppmvd	0.08	-0.02	0.42	0.16
CO	lb/hr,ISO	0.28	-0.07	1.41	0.54
CO	lb/hr	0.27	-0.06	1.38	0.53
VOC	ppmvd	< 0.1	< 0.1	< 0.1	< 0.1
VOC	lb/hr	<0.18	<0.18	<0.18	<0.18
NO_x	ppmvd @ 15% O_2	7.6	7.5	7.2	7.4
NO_x	lb/hr, ISO	51.6	50.8	47.6	50.0
NO_x	lb/hr	50.0	49.2	46.5	48.6

Table 4-3. Emission Summary Table for Shady Hills Generating Station, Pasco County, FL - Unit 2
Approximately 100% Base Load Conditions on Distillate Oil

Test Identification					
Test Period	--	1	2	3	Average
Test Condition	load level, %	100	100	100	
Sampling Location	--	stack	stack	stack	
Date	--	28-Jan-02	28-Jan-02	28-Jan-02	
Test Time (start-stop)	--	1433-1533	1553-1653	1715-1815	
Ambient Conditions					
Barometric Pressure	In. Hg	30.17	30.17	30.17	30.17
Ambient Temperature	°F	86	86	76	82.7
Wet Bulb Temperature	°F	73	73	68	71.0
Absolute Humidity	lb water/lb dry air	0.01390	0.01390	0.01242	0.01341
Turbine Operating Conditions					
Mean Turbine Exhaust Temp., TTXM	°F	1103.4	1101.6	1097.0	1100.7
Fuel Flow, FQLM1	lb/sec	27.90	27.95	28.23	28.03
Compressor Inlet Temperature, CTIM	°F	80.3	79.1	75.0	78.1
Specific Humidity, CMHUM	lb/lb	0.01370	0.01410	0.01160	0.01313
Inlet Guide Vane Angle, CSGV	degrees	86.0	86.0	86.0	86.0
Generator Output, DWATT	mw	175.9	176.5	178.9	177.1
Compressor Discharge Pressure, CPD	psig	218.2	219.3	221.4	219.6
Exhaust Gas Conditions					
Volumetric Flow, M-19, F_d	dscfm	770,477	777,597	801,273	783,116
Volumetric Flow, M-19, F_c	dscfm	798,118	787,413	793,963	793,165
Moisture	%V	11.9	11.4	11.6	11.7
O_2	%	12.77	12.83	12.99	12.9
CO_2	%	5.84	5.93	5.94	5.9
NO_x	ppmvd	51.75	52.14	52.03	51.97
Exhaust Emissions					
Visible Emissions	%	0.0	0.0	0.0	0.0
SO_2	lb/hr	87.9	87.9	87.9	87.9
SO_2	%sulfur	0.0438	0.0438	0.0438	0.0438
CO	ppmvd	0.83	0.73	0.68	0.7
CO	lb/hr, ISO	3.16	2.77	2.55	2.83
CO	lb/hr	2.90	2.55	2.42	2.63
VOC	ppmvw	< 0.1	0.1	< 0.1	< 0.1
VOC	lb/hr	<0.18	0.18	<0.18	<0.18
NO_x	ppmvd @ 15% O_2	37.6	38.1	38.8	38.2
NO_x	lb/hr, ISO	310.5	315.7	314.4	313.5
NO_x	lb/hr	285.6	290.5	298.7	291.6

4.2 Quality Control Procedures and Results

Specific quality assurance and quality control (QA/QC) procedures were followed during this test program to ensure the production of useful and valid data. The QA/QC checks and procedures described in this section are an integral part of the overall sampling scheme. The acceptance criteria, control limits and corrective action that were followed are summarized in Table 4-4. All measurements were within cited control limits. Supporting documentation for each of these quality control measures are provided in the Appendices.

4.2.1 Continuous Emission Monitors Data Quality

Continuous monitoring for NO_x, CO, O_2, and CO_2 was performed using the instruments discussed in Section 3. Quality control procedures for all instruments are similar. The primary control check for precision of the continuous monitors was the analysis of control standards. The control standards were used to calibrate the instruments at the beginning and end of each day and to check instrument drift as required after each run. EPA Protocol 1 gases were used.

Calibration and Linearity Check

Analyzer calibration was performed at least once each test day. Analyzer response for NO_x, VOC and CO was set using low, mid and high level span gases. Analyzer response for O_2, and CO_2 was set using the zero, mid and high level span gases. Subsequent response to the calibration gases were within the limits shown in Table 4-4.

Drift Checks

At the beginning and end of each test run, zero and upscale gases were introduced into the instruments as required by the reference methods. Drift for each test was determined using the results of the pre-test and post-test calibration checks.

Other QC Checks

Records of daily leak checks, sample line bias checks and response time checks were performed according to the specifications in the reference methods and listed in Table 3-1. Results of each of these checks are provided in Appendix A. A test of the NO_2 to NO conversion efficiency of the NO_x analyzer was performed according to the specifications in EPA Method 20.

Table 4-4. Quality Control Checks

Criteria	Control Limits	Corrective Action
Instrument Measurements: General		
Line Leak Check	<0.5% O_2	Locate & repair leak, recheck
Manifold Leak Check	<0.5% O_2	Locate & repair leak, recheck
Instrument Measurements: NO_x, O_2, and CO_2		
Calibration Error (low & high level)	±2.0% of span	Adjust instrument, recalibrate
Drift Between Runs (zero & mid-level)	±2.0% of span	Adjust data for drift
Response Time	Less than 30 seconds	Increase sample flow rate
NO_2 to NO Conv. Efficiency	>90% conversion	Replace converter, recheck
Instrument Measurements: CO		
Calibration Error (low & mid-level)	±2.0% of full scale	Adjust instrument, recalibrate
Drift (zero, mid & high-level)	±10.0% of span in 8 hrs.	Adjust data for drift
Response time	Less than 30 seconds	Increase sample flow rate
Instrument Measurements: VOC		
Calibration Error (low & mid-level)	±5.0% of gas value	Adjust instrument, recalibrate
Drift Between Runs (zero & mid-level)	±3.0% of span	Adjust data for drift
Response Time	None	Record response time
Manual Sampling		
Final Leak Rate	≤0.02 acfm or 4% of sampling rate whichever is less	Adjust sample volume
Dry Gas Meter Calibration	Post average factor (g) agree ±5% of pre-factor	Adjust sample volumes using the g that gives smallest volume
Indiv. Correction Factors (Y_i)	Agree within 2% of average factor	Redo correction factor
Average Correction Factor	1.00 ±1%	Adjust the dry gas meter and recalibrate
Intermediate Dry Gas Meter	Calibrated every 6 months against EPA standard	--

4.2.2 Quality Control Procedures for Manual Sampling

Gas Sample Volume Determination (by EPA Method 4)

The raw volume indicated by the dry gas meter was corrected to a standard volume, using measurements of the actual meter pressure and temperature and the meter calibration factor. The meter calibration factor was established prior to the test using a set of calibration orifices. Pre-test and post-test leak checks were performed to ensure no leakage of ambient air into the system thereby biasing the stack gas sample volume determination.

Moisture Determination QA/QC

The moisture content of the gas stream was determined using EPA Method 4. The moisture value was used to correct the wet VOC measurements to a dry basis. In order to assure good moisture data, several quality control procedures were followed. The balance used for weighing impingers was electronically checked for accuracy and with standard calibration weights periodically. The indicating silica gel in the moisture trains was checked for saturation after each run and changed if necessary. The impinger exit gas temperature was monitored during the run, and sufficient ice was maintained in the impinger bucket to keep the temperature lower than 68°F.

Sample Custody Procedures

Custody procedures for fuel samples included careful documentation of sample collection, and the use of chain-of-custody records for sample transportation. The sample containers were each tagged with a unique sample identification number. This number appeared on the chain-of-custody records, and was carried through the laboratory to appear on the final analytical reports. The Field Team Leader was responsible for ensuring that proper custody and documentation procedures are followed for sampling and analysis.

Data gathered at the sampling locations, including sampling times and any special conditions associated with specific samples, was recorded in the test log. Prepared data sheets were used to record ambient data. Required sampling intervals and actual sampling times were clearly noted on the data sheets. Electronically recorded data was downloaded daily from the computer hard drive to floppy disks for backup.

4.2.3 Data Reduction, Validation, and Reporting

All data and calculations for flow rates and moisture concentrations were made using a computer spreadsheet. Calculated data was validated by an independent check. A predetermined input data set with known expected output values was entered to each spreadsheet to confirm proper function. All hand calculations were spot checked for accuracy and completeness on-site by the Field Engineer.

All measurement data were validated based on the following criteria:

- Stable process conditions during sampling and testing;
- Acceptable sample collection procedures;
- Consistency with other expected results; and
- Adherence to prescribed QC procedures.

SHADY HILLS GENERATING STATION
UNIT 3 EMISSION TESTS SUMMARY

EXECUTIVE SUMMARY

Coastal Air Consulting, Inc. (Coastal) performed emission testing at the Shady Hills Generating Station in Pasco County, Florida. Testing was performed to demonstrate compliance with conditions cited in Florida Department of Environmental Protection Permit No. PSD-FL-280, DEP Facility No. 1010373. The testing was completed on Unit 3 firing natural gas on February 19 & 20, 2002 and on Unit 3 firing distillate oil on February 18, 2002.

This unit is a General Electric stationary, combustion turbine (PG7241FA, Frame 7FA) operated in the simple cycle mode. The Frame 7FA gas turbine operates on natural gas in the dry low NO_x (DLN) mode. This unit is also equipped for water injection for NO_x control when firing distillate fuel oil.

Testing was completed at base load conditions while the unit fired natural gas and distillate oil. The parameters measured include carbon monoxide, nitrogen oxides, volatile organic compounds, flue gas moisture, opacity and flue gas volumetric flow rate (calculated). The results of the testing demonstrated that actual emissions are below all applicable air emissions permit limits. Test results (average of three runs) are summarized below:

Parameter	100% Load	Allowable
NOx, ppmvd, @ 15% O_2		
natural gas	7.3	9
distillate oil	36.9	42
NOx, lb/hr, ISO		
natural gas	46.4	64.1
distillate oil	294.6	351
CO, ppmvd		
natural gas	0.37	12
distillate oil	0.38	20
CO, lb/hr, ISO		
natural gas	1.23	42.5
distillate oil	1.38	71.4
VOCs, ppmvd		
natural gas	0.1	1.4
VOCs, ppmvw		
distillate oil	<0.1[a]	7
VOCs, lb/hr		
natural gas	0.18	2.8
distillate oil	<0.18	16.2
SO_2, gr/100 scf, natural gas	0.0013	1
SO_2, % sulfur, distillate oil	0.0392	0.05
SO_2, lb/hr		
natural gas	0.558	5
distillate oil	78.7	98.7
Visible Emissions, %		
natural gas	0.0	10
distillate oil	0.0	10

[a]– Value is below detection limit

STATEMENT OF VALIDITY

Shady Hills Generation Station
Coastal Air Consulting Report
March 22, 2002

I hereby certify the information and data provided in this emissions test report for tests conducted at the Shady Hills Generating Station Unit 3 in Pasco County, Florida are true and correct, to the best of my knowledge.

Stephen C. Webb
President

Table of Contents

Tables

1.0 INTRODUCTION

Shady Hills Generating Station is located in Pasco County, Florida. This report summarizes the data collected during testing on Unit 3. The unit is a simple cycle General Electric stationary combustion turbine (PG7241FA, Frame 7FA). The Frame 7FA gas turbine operates on natural gas in the dry low NO_x (DLN) mode. This unit is also equipped for water injection for NOx control when firing distillate oil. This report summarizes results for testing when firing natural gas and distillate oil.

Coastal Air Consulting, Inc. was contracted by Lockwood Greene E & C to perform the initial compliance test demonstration.

1.1 Purpose and Objectives

The data collected during this testing will be used by Lockwood Greene E & C to demonstrate compliance with air emission permit requirements.

Table 1-1 provides a matrix of parameters, load conditions and purposes of the testing.

TABLE 1-1. Test Matrix and Purpose of Testing

Parameter (both fuels)	EPA Test Methods	100% Load
NOx	EPA M20	Permit
CO	EPA M10	Permit
VOC	EPA M25A	Permit
Moisture	EPA M4	Info
VE	EPA M9	Permit
O_2	EPA M3A	Info
CO_2	EPA M3A	Info
Stack Flowrate	EPA M19 calc.	Info

Three runs per 100% load condition; VOC – volatile organic compounds;
Permit – air permit requirement; Info – internal information or supporting other data requirements;
Natural gas sample collected during each test day and analyzed for composition (ultimate), specific gravity, and heating value.
Distillate oil sample collected during each test day and analyzed for composition (ultimate), specific gravity, and heating value.

1.2 Test Program Organization

The primary contacts for the test program were:

Lockwood Greene E &C Personnel
Robert Chalfant, Manager air quality services (404) 818-8325
James Riley, Project Engineer, (404) 818-8155
Don Dickerson, Environmental Project Manager, On-site contact, (706) 724-8225
Coastal Personnel
Stephen Webb, President/field team leader, (386) 943-9241
Robert Righter, Chemist, (386) 943-9241

1.3 Project Test Plan

Coastal followed the methodology and procedures cited in the document entitled "Air Emissions Performance Tests" for Shady Hills Power, dated October 4, 2001.

There were no significant deviations from the Test Plan. There was no significant data quality problems encountered during this testing. The original test plan called for on-line GC sample and analysis for methane and ethane. The total hydrocarbons measurements never exceeded the minimum detection limit therefore the methane/ethane analysis was not necessary.

Performance testing for demonstration of compliance with emission limits in Permit No. PSD-FL-280 and 40 CFR 60 Subpart GG was conducted at base load conditions (nominal 100% capacity). This single operating load testing is consistent with the May 26, 2000 letter from U.S. EPA Region 4 to the Region 4 Air Division Directors addressing routine alternative testing procedures for combustion turbines (CTs) under NSPS. The EPA letter specifies that for CTs equipped with NOx CEMS, the monitors will provide credible evidence regarding the unit's compliance status on a continuous basis following the initial test, and level of compliance assurance provided in this case is sufficient to justify approval of requests that initial performance testing be allowed at a single operating load. The CTs are equipped with CEMS in accordance with the PSD permit and 40 CFR Part 75 requirements. A letter requesting approval of single operating load testing was submitted to and approval was confirmed with Mr. Joseph Kahn of the Florida DEP Emissions Monitoring Section.

1.4 Report Contents

The remainder of this Report is comprised of four Sections and Appendices. Section 2 contains a brief summary of the results in comparison to the compliance demonstration requirements. Section 3 provides a description of the procedures followed for the testing as specified in the Test Plan. Section 4 contains detailed summaries of emission testing results and associated quality control measures.

The Appendices contain all supporting documentation for the results presented in this report.

2.0 SUMMARY OF RESULTS

The emission tests for Unit 3 natural gas and Unit 3 distillate oil were conducted under the conditions specified in the Emission Test Plan dated October 4, 2001 that was previously prepared by Lockwood Greene E & C. There were no significant deviations from the standard test procedures set within the plan.

Results of three test runs are averaged and presented in Table 2-1 for comparison to the air permit emission limits. A more complete discussion of the results is provided in Section 4. All reported emissions are below the air construction permit emission limits and standards.

Table 2-1. Summary of Results

Parameter	100% Load	Allowable
NOx, ppmvd, @ 15% O_2		
natural gas	7.3	9
distillate oil	36.9	42
NOx, lb/hr, ISO		
natural gas	46.4	64.1
distillate oil	294.6	351
CO, ppmvd		
natural gas	0.37	12
distillate oil	0.38	20
CO, lb/hr, ISO		
natural gas	1.23	42.5
distillate oil	1.38	71.4
VOCs, ppmvd		
natural gas	0.1	1.4
VOCs, ppmvw		
distillate oil	<0.1[a]	7
VOCs, lb/hr		
natural gas	0.18	2.8
distillate oil	<0.18	16.2
SO_2, gr/100 scf, natural gas	0.0013	1
SO_2, % sulfur, distillate oil	0.0392	0.05
SO_2, lb/hr		
natural gas	0.558	5
distillate oil	78.7	98.7
Visible Emissions, %		
natural gas	0.0	10
distillate oil	0.0	10

[a]– Value is below detection limit

3.0 TEST PROGRAM DESCRIPTION

Coastal configured a sampling/monitoring strategy consistent with the requirements cited in the Air Construction Permit No.PSD-FL-280, the associated emission limits and GE's air emission performance guarantees.

This subsection identifies the procedures that were followed to demonstrate compliance with air permit emission limits and 40 CFR Part 60 Subpart GG New Source Performance Standards (NSPS), as applicable. All compliance testing was completed in strict accordance with the methods, as applicable. Manual testing according to EPA Reference Method 4 was included in this project.

Table 3-1 summarizes the monitoring procedures followed for the demonstration testing.

Table 3-1. Instrument Specifications

Analyte	Instrument/Principal	Range Specifications	Calibration Values
NO_x by EPA Method 20	Beckman Model 951A, Chemiluminscence	0-25 ppm (for gas) 0-100 ppm (for oil)	0, 5.93, 11.6, 22.2 0, 27.12, 42.2,85.7
O_2 by EPA Method 3A	Servomex 1400 Paramagnetic	0-25 percent	0, 13.1, 21.98
CO_2 by EPA Method 3A	Servomex 1400 Infrared	0-20 percent	0, 3.41, 16.77
CO by EPA Method 10	TECO Model 48 CTL NDIR w/GFC	0-50 ppm	0, 2.9, 6.1
VOCs by EPA Method 25A (for total unburned hydrocarbon)	California Analytical flame ionization detector (THC)	0-20 ppm for THC monitor	0, 6.16, 9.78, 16.9

The procedures for the measurements during this program were primarily instrumentation techniques using continuous emission monitors. Coastal's continuous emission monitoring system (CEMS) is housed inside a mobile laboratory.

Sample gas extracted from the source being monitored was first cleaned and dried before analysis (except total hydrocarbons). The gas was conditioned by passing through a heat-traced Teflon line into a condenser-style moisture removal system prior to analysis for NO_x, CO_2, O_2 and CO. The conditioning system cools the gas to approximately 35 °F and thereby condenses out most of the moisture in the sample. The system is operated with chilled condensers, which are

continuously drained thereby minimizing the possibility of scrubbing target compounds. The flow rate is monitored and controlled through a series of valves and rotometers.

A separate system was used for the total hydrocarbon monitoring. The sample gas was transported directly to the analyzer (unconditioned) through a heat-traced Teflon sample line.

Calibrations were performed with EPA Protocol 1 gases. The Protocol 1 gas certifications are included in the Appendices.

Output from each analyzer was compiled on a microprocessor controlled data acquisition system. One-minute averages were recorded and translated to a computer spreadsheet for further data reduction. All data were printed on site and stored electronically including at least one backup file.

The following subsections provide brief descriptions of the EPA Reference Methods and any technical concerns encountered during the test program. This section also contains information on the fuel analysis and manual moisture measurements that were performed.

3.1 NO_x by EPA Method 20

A Beckman Model 951A analyzer was used to measure NO_x. The operating principle of this instrument is a chemiluminiscent reaction in which ozone reacts with nitric oxide to form oxygen and nitrogen dioxide in an excited state. The excited NO_2 decays rapidly to the unexcited state, emitting a photon that is measured by a photomultiplier tube. The instrument measures total oxides of nitrogen (nitrogen oxide and nitrogen dioxide) by thermally converting nitrogen dioxide to nitrogen oxide in a separate reaction chamber prior to the multiplier tube.

Measurements were performed in accordance with 40 CFR Part 60, Appendix A, EPA Reference Method 20, *Determination of Nitrogen Oxides, Sulfur Dioxides and Diluent Emissions from Gas Turbines*. Three runs were completed at the 100% load condition.

A stratification test was performed as part of the preliminary measurements. Coastal completed a 48-point stratification check measuring and reporting results for oxygen. Coastal then selected the eight monitoring points that reported the lowest oxygen concentrations as the points for monitoring during the compliance tests. EPA Method 20 requires that each point be sampled for a minimum of 1 minute plus response time of the NO_x analyzer. All CEMS instrumentation reported a response time of less than one minute. Each of the selected eight points were monitored for 7.5 minutes to yield a 60-minute run.

Quality control checks specified in EPA Method 20 were performed. These checks include converter efficiency checks, system calibrations and bias checks. This data is reported in Appendix A.

3.2 CO by EPA Method 10

A TECO Model 48CTL trace analyzer was used for the CO monitoring. With this system, concentrations are detected using the nondispersive infrared (NDIR) gas filter correlation technique. Radiation from the infrared source is chopped and then passed through a gas filter alternating between CO and nitrogen due to rotation of the filter wheel. The radiation then passes through an interference filter and enters a multiple pass optical cell where absorption by the sample gas occurs. The CO gas filter produces a reference beam that cannot be further attenuated by CO in the sample cell. At the same time, the nitrogen gas filter produces a measuring beam that can be absorbed by CO in the cell. The chopped detector signal is modulated by the alternation between the two gas filters. The sample amplitude is related to the concentrations of CO in the sample cell.

Coastal followed the requirements of 40 CFR Part 60, Appendix A, EPA Reference Method 10, *Determination of Carbon Monoxide Emissions from Stationary Sources*. Three runs were completed at the 100% load condition.

3.3 CO_2 and O_2 by EPA Method 3A

A Servomex 1400 analyzer was used for the oxygen monitoring. With this system, concentrations are detected using the paramagnetic principle. The analyzer evaluates the paramagnetic susceptibility of the sample gas using a magnetodynamic measuring cell. The response voltage is proportional to the oxygen concentration ratio.

An Servomex 1400 analyzer was used for the carbon dioxide monitoring. This analyzer emits a single beam of infrared radiation at dual wavelengths. The beam passes through a sample cell and radiation at the specific wavelengths is selectively absorbed by the carbon dioxide molecules. The intensity of radiation reaching the end of the sample cell is inversely proportional to the carbon dioxide concentration in the gas.

Coastal followed the requirements of 40 CFR Part 60, Appendix A, EPA Reference Method 3A, *Determination of Oxygen and Carbon Dioxide Concentrations in Emissions from Stationary Sources*. These measurements were made concurrently with all others.

3.4 Total Hydrocarbons by EPA Method 25A

Coastal used a CAI Model 300 analyzer to perform these measurements. In this analyzer, the unconditioned (non-filtered, wet) flue gas enters the flame ionization detector (FID) and the hydrocarbons are combusted in a hydrogen flame. The ions and electrons formed enter an electrode gap, decrease the gas resistance, and permit a current flow in the external circuit. The resulting current is proportional to the instantaneous concentration of unburned hydrocarbons. The results were reported on a methane equivalent basis.

Coastal performed measurements for total hydrocarbons following 40 CFR Part 60, Appendix A, EPA Reference Method 25A *Determination of Total Gaseous Organic Concentration Using a Flame Ionization Analyzer*. Three runs were performed at the 100% load condition. The original test plan called for on-line GC sample and analysis for methane and ethane. The total hydrocarbons measurements never exceeded the minimum detection limit therefore the methane/ethane analysis was not necessary. The mass emission rate was calculated using the minimum detection value.

3.5 Sampling and Analysis of Fuels (Natural Gas & Distillate Oil)

Natural gas samples were collected on February 20, 2002 and the distillate oil samples were collected February 18, 2002. The natural gas samples were shipped to Empact Analytical Systems, Inc. for BTU and specific gravity analysis. Natural gas samples were analyzed according to the procedures outlined in Table 3-2. The oil samples were shipped to Intertek Testing Services of Tampa FL, the analysis is located in Appendix K.

Table 3-2. Fuel Analysis Procedures

Parameter	Procedure	Collection Frequency
Specific Gravity	ASTM D 3588	Two samples collected; one analysis performed.
Heating Value	ASTM D 3588	
Sulfur	ASTM D3246	

The data from the fuel sample analysis were used to calculate flue gas volumetric flow rate using procedures identified in EPA Reference Method 19 and to demonstrate compliance with fuel sulfur content and sulfur dioxide emission limits.

3.6 Stack Gas Volumetric Flow by EPA Method 19

Stack gas volumetric flow rate was calculated using the procedures cited in EPA Method 19. This Method establishes F-factors, which relate to the gas volume of the combustion products to the heat content of the fuel. Data from the fuel analysis was used to calculate oxygen based and carbon dioxide based F-factors. The oxygen-based F-factor was used with the measured fuel feed rates, fuel heating value and oxygen content of the stack gas to calculate the total volumetric flow rate of the stack gas. The CO_2 F-factor, carbon content of the natural gas, along with the fuel feed rate, fuel heating value and carbon dioxide content was used also to calculate stack volumetric flow rate.

3.7 Stack Gas Moisture by EPA Method 4

Moisture content was measured according to EPA Method 4 requirements. A known volume of flue gas was extracted through a series of preweighed/premeasured impingers (two impingers with water, one empty impinger and one silica gel impinger) to assess the mass of water collected. This mass, when compared against the known sample gas volume, was used to calculate flue gas moisture content. The flue gas moisture content was determined for each test condition. Three 30-minute runs were performed during each test condition concurrent with the CEMS measurements. This data was used to convert the measured hydrocarbon concentrations from a wet basis to a dry basis.

3.8 Measurement of Ambient Conditions

Coastal took measurements of barometric pressure (on site barometer) and absolute humidity (sling psychrometer to provide dry bulb and wet bulb temperatures, °F). Measurement frequency was once per run during each condition.

3.9 Process Data

Facility personnel were responsible for collection of all pertinent process data. A hard copy of this data was printed on the Mark VI emission test data display screen at each load stabilization. Data was accumulated and stored on disk during the test runs. Process parameters of interest included:

- Mean turbine exhaust temperature (TTXM), °F
- Fuel flow (FQG) lb/sec (Natural Gas); FQLM1 (Distillate Oil)
- Compressor inlet temperature (CT1F1, CT1F2, CTIM), °F

- Specific Humidity (CMHUM), lb H_2O/lb dry air
- Generator Output (DWATT), MW
- Compressor discharge pressure (CPD), psig
- Inlet Guide Vane Angle (CSGV), degrees

4.0 TEST RESULTS

4.1 Test Narrative

Air emission permit compliance testing was completed on February19 & 20,2002 for Unit 3 natural gas; and February 18, 2002 for Unit 3 distillate oil.

Testing was completed using CEMS procedures and manual test procedures (moisture). All reported results are supported with data contained in the Appendices to this document.

Coastal completed a stack traverse in accordance with EPA Method 20 requirements while the unit was operating near 50 percent of full load. A total of 48 points were monitored (12 points from each of 4 ports) for oxygen content to determine the presence of stratification. The traverse verified the absence of stratification in the stack for both Units.

During the test runs using the CEMS procedures, each sample point was monitored for seven and one half minutes at each of eight selected representative sample points to yield a total of 60 minutes per sample run. Test Runs for moisture content were 30-minutes in duration. The sample periods are consistent with the Emission Test Plan and the requirements of EPA Reference Method 20.

Three runs were performed at 100 percent of full load. Only air emission permit related parameters are reported in this document.

Table 4-1 summarizes test times and operating conditions.

Table 4-1. Air Emission Permit Limit Compliance Test Sequence
Unit 3 When Firing Natural Gas and Unit 3 When Firing Distillate Oil

Load	Run Number	Date/Time	Comment
Unit 1 when firing natural gas			
50% Load	O2 Traverse	2/19/02, 1830-2034	approximately 85 MW
100% Load	Run 1 Run 2 Run 3	2/20/02, 0900-1000 2/20/02, 1259-1359 2/20/02, 1422-1522	
Unit 1 when firing distillate oil			
50% Load	O2 Traverse	2/18/02, 1017-1159	approximately 85 MW
100% Load	Run 1 Run 2 Run 3	2/18/02, 1333-1433 2/18/02, 1457-1557 2/18/02, 1614-1714	

Table 4-2 summarize the results of the air emission testing on a per run basis for Unit 3 firing natural gas. Table 4-3 present the results for testing on Unit 3 firing distillate oil.

Table 4-2. Emission Summary Table for Shady Hills Generating Station, Pasco County, FL - Unit 3
Approximately 100% Base Load Conditions on Natural Gas

Test Identification					
Test Period	--	1	2	3	Average
Test Condition	load level, %	100	100	100	
Sampling Location	--	stack	stack	stack	
Date	--	20-Feb-02	20-Feb-02	20-Feb-02	
Test Time (start-stop)	--	0900-1000	1259-1359	1422-1522	
Ambient Conditions					
Barometric Pressure	In. Hg	30.13	30.13	30.13	30.13
Ambient Temperature	°F	68	80	78	75.3
Wet Bulb Temperature	°F	61	64	64	63.0
Absolute Humidity	lb water/lb dry air	0.00958	0.00872	0.00919	0.00916
Turbine Operating Conditions					
Mean Turbine Exhaust Temp., TTXM	°F	1110.9	1116.5	1116.1	1114.5
Fuel Flow, FQG	lb/sec	19.88	19.47	19.46	19.60
Compressor Inlet Temperature, CTIM	°F	54.1	55.0	56.5	55.2
Specific Humidity, CMHUM	lb/lb	0.00880	0.0110	0.01080	0.01020
Inlet Guide Vane Angle, CSGV	Degrees	84.3	86.0	86.0	85.4
Generator Output, DWATT	Mw	168.5	164.4	164.1	165.6
Compressor Discharge Pressure, CPD	psig	213.2	210.2	210.3	211.2
Exhaust Gas Conditions					
Volumetric Flow, M-19, F_d	dscfm	701,752	693,137	699,738	698,209
Volumetric Flow, M-19, F_c	dscfm	693,998	695,055	696,448	695,167
Moisture	%V	8.0	8.8	9.1	8.6
O_2	%	13.80	13.86	13.93	13.86
CO_2	%	4.07	3.98	3.97	4.01
NO_x	ppmvd	8.99	8.75	8.54	8.76
Exhaust Emissions					
Visible Emissions	%	0.0	0.0	0.0	0.0
SO_2	lb/hr	0.558	0.558	0.558	0.558
SO_2	gr/100 scf	0.0013	0.0013	0.0013	0.0013
CO	ppmvd	0.21	0.11	0.79	0.37
CO	lb/hr,ISO	0.69	0.37	2.63	1.23
CO	lb/hr	0.67	0.34	2.46	1.16
VOC	ppmvd	0.13	< 0.1	< 0.1	0.1
VOC	lb/hr	0.24	<0.18	<0.18	<0.18
NO_x	ppmvd @ 15% O_2	7.5	7.3	7.2	7.3
NO_x	lb/hr, ISO	46.7	46.8	45.8	46.4
NO_x	lb/hr	45.2	43.5	42.8	43.8

Table 4-3. Emission Summary Table for Shady Hills Generating Station, Pasco County, FL - Unit 3
Approximately 100% Base Load Conditions on Distillate Oil

Test Identification					
Test Period	--	1	2	3	Average
Test Condition	load level, %	100	100	100	
Sampling Location	--	stack	stack	stack	
Date	--	18-Feb-02	18-Feb-02	18-Feb-02	
Test Time (start-stop)	--	1333-1433	1457-1557	1614-1714	
Ambient Conditions					
Barometric Pressure	In. Hg	30.22	30.22	30.22	30.22
Ambient Temperature	°F	69	69	69	69.0
Wet Bulb Temperature	°F	56	56	55	56.0
Absolute Humidity	lb water/lb dry air	0.00632	0.00632	0.00576	0.00613
Turbine Operating Conditions					
Mean Turbine Exhaust Temp., TTXM	°F	1072.4	1072.8	1073.0	1072.7
Fuel Flow, FQLM1	lb/sec	27.92	27.97	28.29	28.06
Compressor Inlet Temperature, CTIM	°F	53.0	53.4	53.3	53.2
Specific Humidity, CMHUM	lb/lb	0.00880	0.00830	0.00840	0.00850
Inlet Guide Vane Angle. CSGV	degrees	86.0	86.0	86.0	86.0
Generator Output, DWATT	mw	190.1	190.0	190.0	190.1
Compressor Discharge Pressure, CPD	psig	230.1	229.9	229.9	229.9
Exhaust Gas Conditions					
Volumetric Flow, M-19, F_d	dscfm	771,423	779,533	787,472	779,476
Volumetric Flow, M-19, F_c	dscfm	760,379	761,741	770,456	764,192
Moisture	%V	10.8	11.2	11.8	11.3
O_2	%	12.79	12.86	12.85	12.83
CO_2	%	6.13	6.13	6.13	6.13
NO_x	ppmvd	50.50	50.41	50.37	50.43
Exhaust Emissions					
Visible Emissions	%	0.0	0.0	0.0	0.0
SO_2	lb/hr	78.7	78.7	78.7	78.7
SO_2	%sulfur	0.0392	0.0392	0.0392	0.0392
CO	ppmvd	0.23	0.44	0.46	0.38
CO	lb/hr, ISO	0.84	1.61	1.69	1.38
CO	lb/hr	0.81	1.54	1.61	1.32
VOC	ppmvw	0.1	<0.1	< 0.1	< 0.1
VOC	lb/hr	0.19	<.18	<0.18	<0.18
NO_x	ppmvd @ 15% O_2	36.7	37.1	36.9	36.9
NO_x	lb/hr, ISO	291.9	294.5	297.2	294.6
NO_x	lb/hr	279.1	281.5	284.2	281.6

4.2 Quality Control Procedures and Results

Specific quality assurance and quality control (QA/QC) procedures were followed during this test program to ensure the production of useful and valid data. The QA/QC checks and procedures described in this section are an integral part of the overall sampling scheme. The acceptance criteria, control limits and corrective action that were followed are summarized in Table 4-4. All measurements were within cited control limits. Supporting documentation for each of these quality control measures are provided in the Appendices.

4.2.1 Continuous Emission Monitors Data Quality

Continuous monitoring for NO_x, CO, O_2, and CO_2 was performed using the instruments discussed in Section 3. Quality control procedures for all instruments are similar. The primary control check for precision of the continuous monitors was the analysis of control standards. The control standards were used to calibrate the instruments at the beginning and end of each day and to check instrument drift as required after each run. EPA Protocol 1 gases were used.

Calibration and Linearity Check

Analyzer calibration was performed at least once each test day. Analyzer response for NO_x, VOC and CO was set using low, mid and high level span gases. Analyzer response for O_2, and CO_2 was set using the zero, mid and high level span gases. Subsequent response to the calibration gases were within the limits shown in Table 4-4.

Drift Checks

At the beginning and end of each test run, zero and upscale gases were introduced into the instruments as required by the reference methods. Drift for each test was determined using the results of the pre-test and post-test calibration checks.

Other QC Checks

Records of daily leak checks, sample line bias checks and response time checks were performed according to the specifications in the reference methods and listed in Table 3-1. Results of each of these checks are provided in Appendix A. A test of the NO_2 to NO conversion efficiency of the NO_x analyzer was performed according to the specifications in EPA Method 20.

Table 4-4. Quality Control Checks

Criteria	Control Limits	Corrective Action
Instrument Measurements: General		
Line Leak Check	<0.5% O_2	Locate & repair leak, recheck
Manifold Leak Check	<0.5% O_2	Locate & repair leak, recheck
Instrument Measurements: NO_x, O_2, and CO_2		
Calibration Error (low & high level)	±2.0% of span	Adjust instrument, recalibrate
Drift Between Runs (zero & mid-level)	±2.0% of span	Adjust data for drift
Response Time	Less than 30 seconds	Increase sample flow rate
NO_2 to NO Conv. Efficiency	>90% conversion	Replace converter, recheck
Instrument Measurements: CO		
Calibration Error (low & mid-level)	±2.0% of full scale	Adjust instrument, recalibrate
Drift (zero, mid & high-level)	±10.0% of span in 8 hrs.	Adjust data for drift
Response time	Less than 30 seconds	Increase sample flow rate
Instrument Measurements: VOC		
Calibration Error (low & mid-level)	±5.0% of gas value	Adjust instrument, recalibrate
Drift Between Runs (zero & mid-level)	±3.0% of span	Adjust data for drift
Response Time	None	Record response time
Manual Sampling		
Final Leak Rate	≤0.02 acfm or 4% of sampling rate whichever is less	Adjust sample volume
Dry Gas Meter Calibration	Post average factor (g) agree ±5% of pre-factor	Adjust sample volumes using the g that gives smallest volume
Indiv. Correction Factors (Y_i)	Agree within 2% of average factor	Redo correction factor
Average Correction Factor	1.00 ±1%	Adjust the dry gas meter and recalibrate
Intermediate Dry Gas Meter	Calibrated every 6 months against EPA standard	--

4.2.2 Quality Control Procedures for Manual Sampling

Gas Sample Volume Determination (by EPA Method 4)

The raw volume indicated by the dry gas meter was corrected to a standard volume, using measurements of the actual meter pressure and temperature and the meter calibration factor. The meter calibration factor was established prior to the test using a set of calibration orifices. Pre-test and post-test leak checks were performed to ensure no leakage of ambient air into the system thereby biasing the stack gas sample volume determination.

Moisture Determination QA/QC

The moisture content of the gas stream was determined using EPA Method 4. The moisture value was used to correct the wet VOC measurements to a dry basis. In order to assure good moisture data, several quality control procedures were followed. The balance used for weighing impingers was electronically checked for accuracy and with standard calibration weights periodically. The indicating silica gel in the moisture trains was checked for saturation after each run and changed if necessary. The impinger exit gas temperature was monitored during the run, and sufficient ice was maintained in the impinger bucket to keep the temperature lower than 68°F.

Sample Custody Procedures

Custody procedures for fuel samples included careful documentation of sample collection, and the use of chain-of-custody records for sample transportation. The sample containers were each tagged with a unique sample identification number. This number appeared on the chain-of-custody records, and was carried through the laboratory to appear on the final analytical reports. The Field Team Leader was responsible for ensuring that proper custody and documentation procedures are followed for sampling and analysis.

Data gathered at the sampling locations, including sampling times and any special conditions associated with specific samples, was recorded in the test log. Prepared data sheets were used to record ambient data. Required sampling intervals and actual sampling times were clearly noted on the data sheets. Electronically recorded data was downloaded daily from the computer hard drive to floppy disks for backup.

4.2.3 Data Reduction, Validation, and Reporting

All data and calculations for flow rates and moisture concentrations were made using a computer spreadsheet. Calculated data was validated by an independent check. A predetermined input data set with known expected output values was entered to each spreadsheet to confirm proper function. All hand calculations were spot checked for accuracy and completeness on-site by the Field Engineer.

All measurement data were validated based on the following criteria:

- Stable process conditions during sampling and testing;
- Acceptable sample collection procedures;
- Consistency with other expected results; and
- Adherence to prescribed QC procedures.

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
APPROVAL OF ONE LOAD TESTING

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

April 8, 2002

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Kennard F. Kosky, P.E
Principal
Golder Associates Inc
6241 NW 23rd Street, Suite 500
Gainesville, Florida 32653-1500

Re: Request For One Load Testing
Shady Hills Generating Station Combustion Turbines Units 1 through 3
DEP File No. PSD-FL-280 (1010373-001-AC)

Dear Mr. Kosky:

The Department has reviewed your letter dated February 27, 2002, on behalf of Shady Hills Generating Station (SHGS) requesting to perform one-load testing on their combustion turbines for their determination of initial compliance. Following is the response to the regulatory issue you submitted for our review and concurrence.

Department Response: Based on the guidance given in the EPA memo dated May, 26 2000, this facility is hereby authorized to test at a single load in lieu of the four 4 loads. CEMS will be used for continuous compliance with the NO_X standards. Refer to Appendix GG, attached.

A copy of this letter and attached Appendix GG shall be filed with the referenced permit and shall become part of the permit. This permitting decision is issued pursuant to Chapter 403, Florida Statutes.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida, 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within fourteen days of receipt of this notice of intent. Petitions filed by any persons other than those entitled to written notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any

subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

A petition that disputes the material facts on which the Department's action is based must contain the following information: (a) The name and address of each agency affected and each agency's file or identification number, if known; (b) The name, address, and telephone number of the petitioner, the name, address, and telephone number of the petitioner's representative, if any, which shall be the address for service purposes during the course of the proceeding; and an explanation of how the petitioner's substantial interests will be affected by the agency determination; (c) A statement of how and when petitioner received notice of the agency action or proposed action; (d) A statement of all disputed issues of material fact. If there are none, the petition must so indicate; (e) A concise statement of the ultimate facts alleged, including the specific facts the petitioner contends warrant reversal or modification of the agency's proposed action; (f) A statement of the specific rules or statutes the petitioner contends require reversal or modification of the agency's proposed action; and (g) A statement of the relief sought by the petitioner, stating precisely the action petitioner wishes the agency to take with respect to the agency's proposed action.

A petition that does not dispute the material facts upon which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above. Mediation is not available in this proceeding.

In addition to the above, a person subject to regulation has a right to apply for a variance from or waiver of the requirements of particular rules, on certain conditions, under Section 120.542 F.S. The relief provided by this state statute applies only to state rules, not statutes, and not to any federal regulatory requirements. Applying for a variance or waiver does not substitute or extend the time for filing a petition for an administrative hearing or exercising any other right that a person may have in relation to the action proposed in this notice of intent.

The application for a variance or waiver is made by filing a petition with the Office of General Counsel of the Department, 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. The petition must specify the following information: (a) The name, address, and telephone number of the petitioner; (b) The name, address, and telephone number of the attorney or qualified representative of the petitioner, if any; (c) Each rule or portion of a rule from which a variance or waiver is requested; (d) The citation to the statute underlying (implemented by) the rule identified in (c) above; (e) The type of action requested; (f) The specific facts that would justify a variance or waiver for the petitioner; (g) The reason why the variance or waiver would serve the purposes of the underlying statute (implemented by the rule); and (h) A statement whether the variance or waiver is permanent or temporary and, if temporary, a statement of the dates showing the duration of the variance or waiver requested.

The Department will grant a variance or waiver when the petition demonstrates both that the application of the rule would create a substantial hardship or violate principles of fairness, as each of those terms is defined in Section 120.542(2) F.S., and that the purpose of the underlying statute will be or has been achieved by other means by the petitioner.

Persons subject to regulation pursuant to any federally delegated or approved air program should be aware that Florida is specifically not authorized to issue variances or waivers from any requirements of any such federally delegated or approved program. The requirements of the program remain fully enforceable by the Administrator of the EPA and by any person under the Clean Air Act unless and until the Administrator separately approves any variance or waiver in accordance with the procedures of the federal program.

This permitting decision is final and effective on the date filed with the clerk of the Department unless a petition is filed in accordance with the above paragraphs or unless a request for extension of time in which to file a petition is filed within the time specified for filing a petition pursuant to Rule 62-110.106, F.A.C., and the petition conforms to the content requirements of Rules 28-106.201 and 28-106.301, F.A.C. Upon timely filing of a petition or a request for extension of time, this order will not be effective until further order of the Department.

Any party to this permitting decision (order) has the right to seek judicial review of it under section 120.68 of the Florida Statutes, by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel, Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000, 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 must be filed within thirty days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida

Howard L. Rhodes

Howard L. Rhodes, Director
Division of Air Resources
Management

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this PERMIT MODIFICATION was sent by certified mail (*) and copies were mailed by U.S. Mail before the close of business on 4/9/02 to the person(s) listed:

Ken Kosky, P.E.*
Bruce Lobach, SHGS
Jerry Kissel, SWD-DEP

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.

Victoria Gibson (Clerk) April 9, 2002 (Date)

SECTION IV. APPENDIX GG
NSPS Subpart GG Requirements for Gas Turbines

NSPS SUBPART GG REQUIREMENTS

[Note: Inapplicable provisions have been deleted in the following conditions, but the numbering of the original rules has been preserved for ease of reference to the original rules. The term "Administrator" when used in 40 CFR 60 shall mean the Department's Secretary or the Secretary's designee. Department notes and requirements related to the Subpart GG requirements are shown in **bold** immediately following the section to which they refer. The rule basis for the Department requirements specified below is Rule 62-4.070(3), F.A.C.]

Pursuant to 40 CFR 60.332 Standard for Nitrogen Oxides:

(a) On and after the date of the performance test required by § 60.8 is completed, every owner or operator subject to the provisions of this subpart as specified in paragraph (b) section shall comply with:

(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 NOx emissions (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.

F = NOx emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of this section.

(3) F shall be defined according to the nitrogen content of the fuel as follows:

Fuel-bound nitrogen (percent by weight)	F (NOx percent 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).

Department requirement: While firing gas, the "F" value shall be assumed to be 0.

[Note: This is required by EPA's March 12, 1993 determination regarding the use of NOx CEMS. The "Y" value for this unit is approximately 10 for natural gas. The equivalent emission standard is 108 ppmvd at 15% oxygen. The emissions standards of this permit is more stringent than this requirement.]

(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.

Pursuant to 40 CFR 60.333 Standard for Sulfur Dioxide:

On and after the date on which the performance test required to be conducted by 40 CFR 60.8 is completed, every owner or operator subject to the provision of this subpart shall comply with:

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

Pursuant to 40 CFR 60.334 Monitoring of Operations:

(b) The owner or operator of any stationary gas turbine subject to the provisions of this subpart shall monitor sulfur content and nitrogen content of the fuel being fired in the turbine. The frequency of determination of these values shall be as follows:

(2) If the turbine is supplied its fuel without intermediate bulk storage the values shall be determined and recorded daily. Owners, operators or fuel vendors may develop custom schedules for determination of the values based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with paragraph (b) of this section.

Department requirement: The requirement to monitor the nitrogen content of natural gas fired is waived. For purposes of complying with the sulfur content monitoring requirements of this rule, the owner or operator shall obtain a monthly report from the vendor indicating the sulfur content of the natural gas being supplied for each month of operation.

[Note: This is consistent with EPA's custom fuel monitoring policy and guidance from EPA Region 4.]

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

(1) *Nitrogen oxides.* Any one-hour period during which the average water-to-fuel ratio, as measured by the continuous monitoring system, falls below the water-to-fuel ratio determined to demonstrate compliance with 40 CFR 60.332 by the performance test required in § 60.8 or any period during which the fuel-bound nitrogen of the fuel is greater than the maximum nitrogen content allowed by the fuel-bound nitrogen allowance used during the performance test required in § 60.8. Each report shall include the average water-to-fuel ratio, average fuel consumption, ambient conditions, gas turbine load, and nitrogen content of the fuel during the period of excess emissions, and the graphs or figures developed under 40 CFR 60.335(a).

Department requirement: NOx emissions monitoring by CEM system shall substitute for the requirements of paragraph (c)(1) because a NOx monitor is required to demonstrate compliance with the standards of this permit. Data from the NOx monitor shall be used to determine "excess emissions" for purposes of 40 CFR 60.7 subject to the conditions of the permit.

[Note: As required by EPA's March 12, 1993 determination, the NOx monitor shall meet the applicable requirements of 40 CFR 60.13, Appendix B and Appendix F for certifying, maintaining, operating and assuring the quality of the system; shall be capable of calculating NOx emissions concentrations corrected to 15% oxygen; shall have no less than 95% monitor availability in any given calendar quarter; and shall provide a minimum of four data points for each hour and calculate an hourly average. The requirements for the CEMS specified by the specific conditions of this permit satisfy these requirements.]

(2) *Sulfur dioxide.* Any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds 0.8 percent.

Pursuant to 40 CFR 60.335 Test Methods and Procedures:

(a) To compute the nitrogen oxides emissions, the owner or operator shall use analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator to determine the nitrogen content of the fuel being fired.

(b) In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided for in 40 CFR 60.8(b). Acceptable alternative methods and procedures are given in paragraph (f) of this section.

(c) The owner or operator shall determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a) as follows:

(1) The nitrogen oxides emission rate (NOx) shall be computed for each run using the following equation:

$$NOx = (NOxo)\ (Pr/Po)^{0.5}\ e^{19(Ho-0.00633)}\ (288°K/Ta)^{1.53}$$

where:

NOx = emission rate of NOx at 15 percent O_2 and ISO standard ambient conditions, volume percent.

NOxo = observed NOx concentration, ppm by volume.

Pr = reference combustor inlet absolute pressure at 101.3 kilopascals ambient pressure, mm Hg.

Po = observed combustor inlet absolute pressure at test, mm Hg.

Ho = observed humidity of ambient air, g H_2O/g air.

e = transcendental constant, 2.718.

Ta = ambient temperature, °K.

Department requirement: The owner or operator is not required to have the NOx monitor required by this permit continuously calculate NOx emissions concentrations corrected to ISO conditions. However, the owner or operator shall keep records of the data needed to make the correction, and shall make the correction when required by the Department or Administrator.

[Note: This is consistent with guidance from EPA Region 4.]

(2) The monitoring device of 40 CFR 60.334(a) shall be used to determine the fuel consumption and the water-to-fuel ratio necessary to comply with 40 CFR 60.332 at 30, 50, 75, and 100 percent of peak load or at four points in the normal operating range of the gas turbine, including the minimum point in the range and peak load. All loads shall be corrected to ISO conditions using the appropriate equations supplied by the manufacturer.

Department requirement: The owner or operator is allowed to conduct initial performance tests at a single load because a NOx monitor shall be used to demonstrate compliance with the BACT NOx limits of this permit.

[Note: This is consistent with guidance from EPA Region 4.]

(3) Method 20 shall be used to determine the nitrogen oxides, sulfur dioxide, and oxygen concentrations. The span values shall be 300 ppm of nitrogen oxide and 21 percent oxygen. The NOx emissions shall be determined at each of the load conditions specified in paragraph (c)(2) of this section.

Department requirement: The owner or operator is allowed to make the initial compliance demonstration for NOx emissions using certified CEM system data, provided that compliance be based on a minimum of three test runs representing a total of at least three hours of data, and that the CEMS be calibrated in accordance with the procedure in section 6.2.3 of Method 20 following each run. Alternatively, initial compliance may be demonstrated using data collected during the initial relative accuracy test audit (RATA) performed on the NOx monitor. The span value specified in the permit shall be used instead of that specified in paragraph (c)(3) above.

[Note: These initial compliance demonstration requirements are consistent with guidance from EPA Region 4. The span value is changed pursuant to Department authority and is consistent with guidance from EPA Region 4.]

(d) The owner or operator shall determine compliance with the sulfur content standard in 40 CFR 60.333(b) as follows: ASTM D 2880-71 shall be used to determine the sulfur content of liquid fuels and ASTM D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels (incorporated by reference – see 40 CFR 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 approval of the Administrator.

Department requirement: The permit specifies sulfur testing methods.

[Note: This requirement establishes different methods than provided by paragraph (d) above, but the requirements are equally stringent and will ensure compliance with this rule.]

(e) To meet the requirements of 40 CFR 60.334(b), the owner or operator shall use the methods specified in paragraphs (a) and (d) of this section to determine the nitrogen and sulfur contents of the fuel being burned. The analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency.

[Note: The fuel analysis requirements of the permit meet or exceed the requirements of this rule and will ensure compliance with this rule.]