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July 9, 2001

RECEIVED

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Mr. Mike Roddy
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BUREAU OF AIR REGULATION Facility#
0490340

RE: Payne Creek Generating Station
Air Permit No. PSD-FL-214A/PA-89-2SSA

Dear Mr. Roddy:

Thank you for your submission of the initial emissions testing protocol for the Payne Creek combustion turbines. The original copy was sent by mail and received by this office May 23, 2001. Due to missing material in the original submission, the corrected protocol was e-mailed to this office on June 15, 2001. For your reference, a copy of the e-mailed document is attached. The Department has reviewed and accepted this protocol with the following comments.

The allowable error figures stated on page 9 are not clearly worded and should be interpreted as per Reference Method 7E (as \pm the applicable percentage of span). The calibration gasses stated on page 10 should include a zero and span gas as well as calibration gasses at $\sim 30\%$ and $\sim 60\%$ of span, as per Reference Method 10. A listing of test personnel contacts is missing and should be sent prior to testing.

Fuel oil sampling was not addressed in the protocol. The samples shall be obtained during the testing period for each turbine, or for one turbine if fuel is drawn from a common source. The oil sample(s) shall be analyzed for heating value (for accurate heat input calculation), sulfur, and metals as required by permit. Fuel bound nitrogen shall be determined if an allowance is required for NO_x emissions. Sample(s) shall be obtained at a point representative of fuel oil entering the turbine combustors. After discussing the matter with the PSD section in Tallahassee, it appears that the analytical procedure specified for arsenic may be in error. An EPA approved analytical method for arsenic determination is Method 7061A, from EPA publication SW-846, entitled *Test Methods for Evaluating Solid Waste, Physical/Chemical Methods*. Heating value and sulfur content of pipeline natural gas may be provided by analysis of samples representative of that delivered to Payne Creek reasonably close to the date of initial compliance testing. This analysis may be obtained from the supplier of the natural gas. Additionally, all fuel oil and natural gas metering devices shall be calibrated according to manufacturer's specifications. A record of calibration data and correction factors shall be submitted with the emissions test report.

Should you have questions regarding this matter you may contact me at 813-744-6100 Ext. 113.

Yours truly,

William E. Schroeder
Environmental Engineer
Southwest District

WES/ws
Attachment
cc: W. Proses
A. Linero
J. Kahn

"More Protection, Less Process"

**PERFORMANCE TEST PROTOCOL
Initial Certification Test**

Combined Cycle Units 1 and 2

for

**Seminole Electric Cooperative Inc.
Payne Creek Generating Station
Bowling Green, Florida**

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1.0 INTRODUCTION

Seminole Electric Cooperative Inc. (Seminole) Payne Creek Generating Station (Payne Creek) is subject to the emissions testing and monitoring requirements as set forth by the Environmental Protection Agency (EPA) in Title 40 of the Code of Federal Regulations (CFR) Parts 60 and 75.

The purpose of the test program as outlined in this performance test protocol is to determine compliance with specific air emission permit limits issued by the Florida Department of Environmental Protection (FDEP) Permit No. PSD-FL-214A/PA-89-25SA. This protocol outlines the procedures to be followed, the test methods to be used, and any differences between the test methods proposed in this document as opposed to the test methods suggested in the referenced air permit.

Testing will be performed on the respective outlet stack (downstream of the Heat Recovery Steam Generator (HRSG)) of the two (2) combined cycle combustion turbine units located at the facility. Testing will be conducted at 95-100% of full load (rated heat input) when firing natural gas as well as No. 2 fuel oil. The testing is required to demonstrate compliance with a total NO_x emissions limit on each unit from Payne Creek, when burning natural gas, of 12 parts per million (ppm) by volume corrected to 15 percent oxygen (O₂) as calculated on a dry basis and when burning No. 2 fuel oil, 42 ppm by volume corrected to fifteen percent oxygen (O₂) as calculated on a dry basis. The testing will be performed in accordance with the requirements as stated in Specific Condition Nos. C.1.a. through C.1.j. of the referenced air permit. In addition to NO_x, emissions of carbon monoxide (CO), particulate matter (PM), sulfur dioxide (SO₂), volatile organic compounds (VOC), sulfuric acid (H₂SO₄) mist, beryllium, arsenic, and visible emissions (VE) will also be determined. These pollutants and their respective emission limitations are described in Table 1. Table 1 also describes the applicable test methods to be used for each pollutant as well as the suggested run times of each reference method.

NOTE: Some emission limitation values and testing requirements differ for select pollutants during the initial certification as opposed to subsequent annual compliance testing. This performance test protocol only addresses the emission limitations and testing requirements applicable to the initial certification as required by the referenced air permit.

The tests for each pollutant will be conducted simultaneously if practicable and where appropriate. Testing is currently scheduled for November 2001, and is subject to change depending on the construction schedule and turbine operating load availability.

**Table 1. Combined Cycle Turbine Units Maximum Allowable Emission Limitations
(Initial Certification Only)**

POLLUTANT/ TEST METHOD/ (RUN LENGTH)²	FUEL	CONCENTRATION	TURBINE EMISSION RATE³ (lb/hr)	FACILITY EMISSION RATE (TPY)	FACILITY EMISSION RATE⁵ (TPY)
NO _x RM 7E (1-hour)	Gas	12 ppmvd @ 15% O ₂	68	596	906
	Oil	42 ppmvd @ 15% O ₂	336	504	
CO RM 10 (1-hour)	Gas	20 ppmvd	71	622	618
	Oil	25 ppmvd	91	136	
PM/PM ₁₀ RM 5B (3-hours)	Gas		7	65	147
	Oil		67	100	
H ₂ SO ₄ Mist RM 8 (1-hour)	Gas		1	6	39
	Oil		22	34	
VOC RM 18 (1-hour)	Gas	5 ppmvd	10	88	99
	Oil	10 ppmvd	21	31	
VE RM 9 (1-hour)	Gas & Oil		≤ 10% opacity		
SO ₂ ASTM Fuel Analysis	Gas		5	47	182
	Oil	0.05% by weight	101	152	
Beryllium SWC Fuel Analysis	Oil		0.0049	0.007	0.007
Arsenic SWC Fuel Analysis	Oil		0.0097	0.014	0.014

¹Flow, O₂/CO₂, and moisture determinations will be made simultaneously where applicable.

²All RM test runs will be performed in triplicate (i.e., three (3) RM runs per pollutant).

³Emission rate in lb/hr/turbine will be determined during initial performance test.

⁴The annual emission limitations for natural gas are based upon two CTs operating at full load for 8,760 hours per year per turbine. The annual emission limitations for No. 2 fuel oil are based upon two CTs operating at full load for 1,500 hours per year per turbine.

⁵If both natural gas and No. 2 fuel oil are used at the facility during the same year.

2.0 FACILITY DESCRIPTION

2.1 Facility Location

Payne Creek Generating Station (ORIS Code 007380) is located at 6697 County Road 663, Bowling Green, Florida, Zip Code 33834. The two combined cycle turbine units are presently being constructed and are expected to be completed on or before September 15, 2001. The units are identical Westinghouse Model 501F (D) combined cycle power plants consisting of two (2) 157.5 MW (nominal) combustion turbines (Units CT1 and CT2), two (2) heat recovery steam generators (HRSGs), and a 173 MW (nominal) steam turbine generator for a total facility-wide nominal rating of 488 MW at base load. Each unit will combust pipeline natural gas (primary) and No. 2 low sulfur fuel oil (back-up only) with a sulfur content limit not to exceed 0.05 percent by weight.

2.2 Unit Description

Each CT at Payne Creek will be dispatched as a gas-fired base load unit. Each unit will be equipped with dry low-NO_x (DLN) combustors and a Selective Catalytic Reduction (SCR)

system for NO_x control when firing natural gas (primary fuel) and wet (water) injection for NO_x control when firing No. 2 fuel oil (backup fuel). Also, each CT will be equipped with a carbon monoxide oxidation catalyst control system. The units will not be equipped with add-on emission controls for particulate or any other of the remaining pollutants. Flue gases from each unit exhaust through separate 18 foot inside diameter circular stacks that have an exit height of 175 feet above ground level.

2.3 Reference Methods Sampling Location

The emission sampling location for both units consist of four (4) equally spaced ports located on each units' 175 foot stack at approximately 157 feet above grade. The stack inside diameter (ID) for both stacks will be 12 feet. All reference method sampling ports will be standard 6-inch flanges. The four reference method sampling port locations will meet the EPA Reference Method 1 (RM 1) criteria for upstream and downstream distances.

3.0 REFERENCE METHOD COMPLIANCE TESTING

This section includes a brief discussion of the test methods that will be used for sampling and analysis at the Payne Creek facility. Any deviations from standard procedures are clearly noted below. Unless stated otherwise, all stack sampling will be performed in strict accordance with the applicable test methods as prescribed in the referenced air permit. Since both CT's are of similar engineering design, further discussion and reference to an individual unit or stack implies reference to both units. Testing will be conducted in triplicate on each unit and each fuel separately (i.e., three (3) test runs per unit per fuel per pollutant). In order to document the tested process conditions, the combustion turbine operator will generate a log of one-minute data, for each of the test runs, of the following CT parameters:

- CT Megawatts
- Fuel Flow
- CT Inlet Temperature
- CT Exhaust Temperature
- IGV Demand
- Combustor Shell Pressure
- Combustor Shell Temperature
- Applicable pollutant control process data
- Applicable HRSG process data

3.1 Sample and Velocity Traverse (RM 1)

The location of the traverse points used to determine the velocity of the stack gas within the circular stack is based on the relation of the stack diameter to the upstream and downstream distances to the nearest flue gas disturbances. The number of traverse points used for the isokinetic sampling techniques (Methods 5B and 8) will be determined from Figure 1-1 of Method 1, Appendix A, 40 CFR Part 60.

3.2 Determination of Non-Sulfuric Acid Particulate Matter and Analysis (RM 5B)

The sampling and analytical procedures used for particulate matter (PM) sampling follow the procedures outlined in Method 5B, Appendix A, 40 CFR Part 60. The PM emissions, which exclude any sulfuric acid (H₂SO₄) particulate matter present, will be based upon the mass

collected on the out-of-stack filter and acetone rinse of the probe nozzle, probe liner, and front-half of the filter holder. In accordance with Specific Condition No. C.1.a. of the referenced air permit, PM sampling will be performed under the premise that all particulate matter will be assumed to have an aerodynamic diameter of less than ten microns (PM₁₀).

Prior to leaving the laboratory, glass fiber filters will be numbered for identification, heated for 2 to 3 hours at $320 \pm 10^{\circ}\text{F}$, desiccated for 2 hours, and pre-weighed to the nearest 0.1 mg. Replicated weighings will be conducted at least 6 hours apart until consecutive measurements agree to within 0.5 mg. Silica gel (indicating type, 6-16 Mesh) will also be pre-weighed to between 200 and 300 grams after drying for 2 hours.

The inside dimensions of each stack will be measured and recorded. The number of sampling points and the location of these points on a traverse will be determined by the guidelines set forth in 40 CFR Part 60, Appendix A, Method 1. These points will then be marked on the probe for easy reference and visibility.

A preliminary traverse will be conducted to determine the range of velocity heads and the pressure of the stack. An approximate stack temperature will also be obtained during the same traverse and an approximate moisture content will be estimated based on knowledge of the emission source type and attendant characteristics as well as prior testing experience. From these data, the correct nozzle size and isokinetic K-factor will be determined.

Cyclonic flow will also be determined at this time. If the average cyclonic flow is indicated to be greater than 20° , the overall flow condition in the stack will be considered unacceptable, and a means of corrective action will be determined.

Specific condition No. B.1.(a) of the referenced air permit implies that the prescribed emission limitations are based upon 1-hour averages. In the interest of sample acquisition integrity and accuracy, it is proposed to perform all particulate matter sampling over an individual test run period of three (3) hours duration. The runs will be performed in triplicate for both natural gas and No. 2 fuel oil, for a total of three 3-hour runs per fuel per unit. If Method 1 indicates that a twelve (12) point traverse should be conducted, the particulate sample will be collected isokinetically for fifteen (15) minutes at each of the 12 sample points in the stack for a total test time of 180 minutes per run. If Method 1 indicates that a twenty-four (24) point traverse should be conducted, the particulate sample will be collected isokinetically for 7.5 minutes at each of the 24 sample points in the stack for a total test time of 180 minutes per run.

The sample train will consist of four (4) impingers with 100 ml of DI water in the first and second impingers. The third impinger will remain empty and the fourth impinger will contain approximately 200 to 300 grams (g) of silica gel. The first and second impingers shall be of the standard Greenburg-Smith design. The third and fourth impingers shall be of the modified Greenburg-Smith design (i.e., an unstricted tip on the glass tube insert of the impinger). After assembling the train with the probe as indicated by Method 5, the system will be leak-checked by plugging the inlet to the probe nozzle and pulling a vacuum of at least 15 inches of mercury (Hg). A leakage rate not in excess of 0.02 cfm will be considered acceptable. The pitot

tube system will also be leak-checked with at least 3 inches of water, and any leaks found will be corrected.

The glass probe and filter assembly will be maintained at a temperature of $320 \pm 25^{\circ}\text{F}$. Crushed ice will be placed around the impingers. After a suitable warm-up period, the nozzle will be placed at the first traverse point with the tip pointing directly into the gas stream. The pump will be started and the sampling rate adjusted to isokinetic conditions. After the required time interval has elapsed, the probe will be repositioned to the next traverse point and isokinetic sampling will be re-established. This will be continued for each point on the traverse until the run is completed. Readings, as identified in Figure 5-2 of RM 5, will be taken at least every 7.5 minutes or if significant changes in stack conditions necessitate additional adjustments in flow rate. At the conclusion of each run, the pump will be turned off and final readings will be recorded. A final leak-check of the system will be performed as previously described at the highest vacuum encountered during testing and a leak-check of the pitot system will be repeated. Again, a leakage rate not in excess of 0.02 cfm will be considered acceptable. If deemed necessary, leak checks will also be performed in between test port changes.

The RM 5B filter will be recovered and placed into a properly identified petri dish or other suitable sample container (Container 1). In addition, any filter material that adhered to the filter holder gasket will be recovered and transferred to the container. The probe nozzle, probe liner, and front-half of the filter holder will be rinsed a minimum three times with acetone. The acetone rinse will be recovered and placed in a separately labeled container (Container 2).

To determine the effluent moisture concentration, the contents of the first three impingers will be measured either volumetrically to the nearest 1.0 ml or gravimetrically to the nearest 0.5 grams (g). The fourth impinger containing the silica gel will be weighed to the nearest 0.5 g. The condensed impinger catches and absorbed silica gel mass will be totaled and applied to the moisture calculation equations provided in Method 4 (see Section 3.8 of this document).

Analysis of the RM 5B sample will be made following the procedures of §4.3 of RM 5 with the following exceptions – initially, the probe sample will be dried at ambient temperature. Then, both the probe and filter samples will be oven-dried at a temperature of 320°F for six (6) hours to volatize any condensed sulfuric acid that may have been collected in the samples. The samples will then be desiccated for 2 hours and be weighed to constant weight.

PM emission rates will be calculated using the standard RM 5 equations. A blank of the sample reagents will be prepared and analyzed in accordance with the procedures in RM 5 for each site visit. The RM 5B blanks (same as RM 5) will include a sample particulate filter and a measured amount of acetone (approximate to the average amount of acetone used during sample recovery). The acetone blank will be evaporated to dryness following the same procedures used to evaporate the RM 5B acetone rinses. The RM 5B acetone rinse sample and filter will be oven dried for six (6) hours at 320°F prior to being placed in the desiccator. After desiccating the sample filter and acetone blank for 24 hours, both will be weighed to a constant weight. The results will be reported to the nearest 0.1 mg.

3.3 Sulfuric Acid (H₂SO₄) Mist Emissions (RM 8)

EPA Method 8 is used to determine combined sulfuric acid mist and sulfur trioxide (SO₃). The sampling procedures and apparatus are identical to EPA Method 5/5B except for the following:

- A filter bypass is used prior to the first impinger replacing the Method 5B filter
- The first impinger contains a solution of 80% isopropyl alcohol (IPA)
- A filter is placed in the connecting glassware between the first and second impinger
- The second and third impingers contain a solution of 3% hydrogen peroxide
- The sampling train is purged with ambient air for 15 minutes following sampling to remove any residual sulfur dioxide from the IPA fraction

Specifically, the H₂SO₄ sample will be collected isokinetically for 5 minutes at each of 12 (or 2.5 minutes at each of 24) sample points in the stack location for a total test time of 60 minutes. A glass probe and stainless steel nozzle assembly will be connected to a sample train consisting of four (4) impingers with 100 milliliters (ml) of 80% IPA in the first impinger, 100 ml of 3 % hydrogen peroxide in both the second and third impingers, and the fourth impinger will contain approximately 200 grams (g) of silica gel. The first and third impingers shall be of the standard Greenburg-Smith design. The second and fourth impingers shall be of the modified Greenburg-Smith design (i.e., an unstricted tip on the glass tube insert of the impinger). A glass filter holder, with a glass frit filter support and a silicone or Teflon rubber gasket, will be placed between the first and second impingers. The filter holder will not be heated, and the sample filter (M5-type) contained inside of the filter support will be untared. All glassware and equipment preparation will adhere to the procedures as outlined in RM 8.

After each test run, the sample train will be purged with ambient air at a rate of the average <H of the test run used for that particular sampling train for a period of 15 minutes.

For sample recovery, the impinger contents, sample filter, and sample rinses will be divided into the following sample containers:

- Container 1. The contents of the first impinger will be transferred to a 250-ml graduated cylinder. The rinse solutions (80 % IPA) from the nozzle, probe, connecting umbilical (if necessary), first impinger, and the front-half of the filter holder will also be added to the graduated cylinder. The solution in the graduated cylinder will then be diluted to 250-ml with 80 % IPA. The untared sample filter will be added and mixed with the contents of the graduated cylinder before being transferred to a storage container. Container 1 will be maintained in a chilled environment.
- Container 2. The contents of the second and third impinger will be transferred to a 1000-ml sample container. The rinse solutions (deionized (DI) water) from the second and third impingers and connecting glassware will also be added to the sample container. The solution in the sample container will be diluted to 1000-ml with DI water. *(NOTE: This container recovery step is optional since this particular portion of the sample catch is not used in the H₂SO₄ recovery and determination process.)*

A blank of the sample reagents will be prepared and analyzed in accordance with the procedures in RM 8 for each site visit. Analysis of samples, blanks, and audit will be made in accordance with procedures outlined in §§4.3-4.5 of RM 8. Analysis will be by the Barium Thorin titration method.

To determine the H₂SO₄ mist concentration, the results of the titration of Container 1 will be entered into the following equation as provided in §6.5 of RM 8:

$$C_{H_2SO_4} = K \times \left(\frac{N \times (V_t - V_{tb}) \times \left(\frac{V_{sol}}{V_a} \right)}{V_{mstd}} \right)$$

Where:

- C_{H₂SO₄} = Concentration of H₂SO₄ and SO₃ (lb/dscf)
- K = 1.081e-4 (lb./meq)
- N = Normality of titrant (meq/ml)
- V_t = Volume of titrant used on sample (ml)
- V_{tb} = Volume of titrant used on blank (ml)
- V_{sol} = Total volume of solution in which sample is contained (ml)
- V_a = Volume of sample aliquot titrated (ml)
- V_{mstd} = Volume of gas sample @ standard conditions (dscf)

A set of three 1-hour test runs will be performed on each unit for both natural gas and No. 2 fuel oil, for a total of three 1-hour runs per fuel per unit.

3.4 Visible Emissions (RM 9)

EPA Method 9 will be used to determine compliance with the opacity limits for the two units. A set of three 1-hour test runs will be performed on each unit for both natural gas and No. 2 fuel oil, for a total of three 1-hour runs per fuel per unit. The percent opacity will be measured (to the nearest 5%) as visible emissions by a trained and certified visible emissions evaluator. The visible emissions evaluator is required to be certified every six months by field trials. Proof of valid certification will be provided in the test report.

Visible emissions will be observed by the qualified evaluator and recorded every fifteen seconds during each 1-hour test run. The average of the three (3) sets of 240 fifteen second readings for each fuel will be compared to the visible emissions limit of ≤ 10% opacity as specified in the referenced air permit.

3.5 Volatile Organic Compounds (RM 18)

In accordance with Specific Condition No. C.1.e. of the referenced air permit, volatile organic compound emissions (VOCs) may be determined by either RM 18 or RM 25A. The term VOC is defined as any carbon containing compound excluding non-organic carbon containing compounds such as CO, CO₂, etc. In addition, the organic compounds methane (CH₄) and ethane (C₂H₆), which are present in the units' emissions are excluded from the definition of VOC. Since RM 25A measures the *total* gaseous organic concentration of vapors including

methane and ethane and since this reference method does not quantify the concentrations of individual organic compounds, VOC determinations made using RM 25A may be biased high if the effluent from the turbines contain methane and/or ethane. Therefore, the VOC's will be quantified using RM18 sampling and analytical procedures incorporating the most recent changes promulgated in February 2000. A set of three 1-hour composite tedlar bag samples will be taken from each unit for both natural gas and No. 2 fuel oil. Samples will be collected using the sampling provisions of RM 18 with off-site gas chromatography (GC) using a flame ionization detector (FID). Off-site analysis will be completed within 24 hours by an independent GC analysis laboratory.

3.6 Instrumental Reference Methods — NO_x (RM 7E) and CO Determination (RM 10)
Source emission testing will be performed to demonstrate compliance with the NO_x requirements specified in the referenced air permit. Specific Condition No. C.1.d. requires that Method 7E (RM 7E) be performed should sampling take place downstream of the HRSG, as is the case for this particular test program. A set of three 1-hour test runs will be performed on each unit for both natural gas and No. 2 fuel oil, for a total of three 1-hour runs per fuel per unit.

The testing is required to demonstrate compliance with a total NO_x emissions limit on each unit from Payne Creek, when burning natural gas, of 12 parts per million (ppm) by volume corrected to 15 percent oxygen (O₂) as calculated on a dry basis and when burning No. 2 fuel oil, 42 ppm by volume corrected to fifteen percent oxygen (O₂) as calculated on a dry basis. Testing will also be performed to verify the turbine vendor's carbon monoxide (CO) emission guarantees to ensure that the Prevention of Significant Deterioration (PSD) threshold is not triggered. As is the case for NO_x, a set of three 1-hour test runs will be performed on each unit for both natural gas and No. 2 fuel oil, for a total of three 1-hour runs per fuel per unit. NO_x and CO samples will be analyzed simultaneously. Method 10 (RM 10) will be used to determine CO emissions. Since RM 7E and 10 are instantaneous, "real time" test methods, NO_x and CO compliance will be determined at the time of the initial certification.

For NO_x, an effluent sample will be extracted continuously from a single, representative point within the stack and a portion of the sample will be conveyed to an instrumental chemiluminescent analyzer for determination of NO_x concentration in ppmvd. RM 7E incorporates by reference the procedures outlined in Method 6C. Hence, all sample conditioning and transport will comply with the requirements as prescribed in RM 6C. To ensure compliance with RM 7E test standards, a three-point (i.e., zero, mid- and high-scale) analyzer calibration error check (i.e., direct analyzer calibration) will be conducted on the NO_x analyzer prior to initiating the compliance testing. For RM 7E, the mid-scale calibration gas is required to be 40-60% of span, while the high-scale calibration gas is required to be 80-100% of span. This check is conducted by sequentially injecting the zero and span calibration gases directly into the analyzer, recording the responses, and comparing these responses to the actual tag values of the calibration gas cylinders. During the direct calibration, it is permissible to set the analyzer for the zero adjustment using the zero calibration gas and the span adjustment using only one of the two upscale calibration gases. The reference calibration gases used during this test program will be certified following EPA Protocol analysis procedures. Copies of the calibration gas "certificates of analysis" will be provided in the final test reports. Acceptable system

performance checks dictate that the difference between the analyzer responses and the respective cylinder tag values will not exceed $\geq 2\%$ of span.

Zero and upscale system calibration checks (i.e., system bias calibration) will be performed both before and after each test run in order to quantify reference measurement system sampling system bias and calibration drift. In instances when the test runs immediately follow one another, the post-cal for the run immediately preceding a subsequent run shall also be the pre-cal for that forthcoming run. Upscale is either the mid- or high-range gas, whichever most closely approximates the flue gas level. During these checks, the calibration gases are introduced into the sampling system at the probe outlet so that they are conveyed throughout the entire sampling system in the same manner as the flue gas samples. Drift is defined as the difference between the pre- and post-test system bias calibration responses. Sampling system bias is defined as the difference between the test run calibration check responses (system bias calibration) and the initial calibration error responses (direct analyzer calibration) as a percentage of span. If an acceptable post-test bias check result is obtained but the zero or upscale drift result exceeds the drift limit, the test run is considered valid; however, the direct analyzer calibration and system bias check procedures must be repeated before conducting the next test run. A run is considered invalid and must be repeated if the post-test zero or upscale calibration check result exceeds the bias specification. Again, the direct analyzer calibration and system bias check procedures must be repeated before conducting the next test run. Acceptable system performance checks dictate that system bias calibration checks will not exceed $\geq 5\%$ of span or, for drift checks, $\geq 3\%$ of span. Tables 2 and 3 summarize the anticipated analyzer spans and calibration gas values to be used on each fuel during this test program.

Table 2. Anticipated Analyzer Spans and Calibration Gas Values (Natural Gas)

ANALYZER	SPAN	CALIBRATION GAS VALUES	
		MID-SCALE	HIGH-SCALE
NO _x	0-20 ppm	8.0-12.0 ppm	16.0-20.0 ppm
CO	0-20 ppm	~6 ppm	~12 ppm
O ₂	0-25%	10.0-15.0%	20.0-25.0%
CO ₂	0-20%	8.0-12.0%	16.0-20.0%

Table 3. Anticipated Analyzer Spans and Calibration Gas Values (No. 2 Fuel Oil)

ANALYZER	SPAN	CALIBRATION GAS VALUES	
		MID-SCALE	HIGH-SCALE
NO _x	0-100 ppm	40.0-60.0 ppm	80.0-100.0 ppm
CO	0-25 ppm	~7.5 ppm	~15 ppm
O ₂	0-25%	10.0-15.0%	20.0-25.0%
CO ₂	0-20%	8.0-12.0%	16.0-20.0%

NOTE: Depending upon concentrations typically seen during equipment setup, analyzer spans and calibration gas values are subject to change.

Emissions of CO will also be extracted continuously from the stack via the same sample transport system as that used for NO_x sampling. A portion of the sample will be conveyed to a Thermo Environmental Instruments (TEI) Model 48C Gas Filter Correlation Non-Dispersive Infrared (GFC/NDIR) analyzer that is used for continuous CO analysis. Determining CO emissions will be determined in a manner identical as that for NO_x with the exception that the two span calibration gases are required to be ~30% and ~60% of the CO analyzer span.

3.7 Instrumental Reference Methods — O₂ and CO₂ Determination (RM 3A)

Oxygen (O₂) and carbon dioxide concentrations will be determined using the procedures described in RM 3A. RM 3A incorporates by reference the same sampling and calibration procedures outlined for the determination of NO_x emissions. O₂ and CO₂ values will be used in order to calculate values of dry gas molecular weight, excess air, and lb/million Btu emission rates where applicable. RM 3A values will be obtained during all pollutant test runs performed throughout the test program.

3.8 Stack Gas Velocity and Volumetric Flow Rate (RM 2) and Moisture Content (RM 4)

Emission rates of NO_x, CO, SO₂, VOC, beryllium, and arsenic will be determined from the isokinetic velocity values obtained during the RM 5B or RM 8 test runs that most closely coincide with the times used to determine the NO_x, CO, SO₂, VOC, beryllium, and arsenic concentrations. If no representative corresponding velocity data is available, separate RM 2, RM 3A, and RM 4 test runs will be performed in order to determine the most accurate emission rates of these remaining pollutants.

The average gas velocity and resultant volumetric flow rate in the stacks will be determined from measurements of the velocity head with a Type S pitot tube simultaneously during the isokinetic RM 5B and RM 8 runs. Calibration of the pitot tubes will be performed to verify the face opening alignments, external tubing diameter, and base-to-opening plane distances. A base line coefficient value of 0.84 will be assigned to each pitot tube. An inclined oil manometer will be used to measure velocity heads and stack static pressure. Flue gas temperatures will also be measured during the traverses using calibrated Type K thermocouples.

The moisture content of the gas stream will also be determined simultaneously during the isokinetic RM 5B and RM 8 runs by extracting the gas sample at a known and regulated rate through the RM 5B and RM 8 glass condenser trains. The condenser trains will consist of four glass impingers connected in series with leak free glass U-tube connectors. The gas samples will be extracted through the impinger trains (maintained below 68°F at all times in an ice bath) with a vacuum pump and the amount of gas sampled will be measured with a calibrated dry gas meter. In the event that separate individual RM 4 results will be needed, samples will be extracted from the stack in a quantity of a minimum of twenty-one (21) dry standard cubic feet per §2.2.2 of RM 4.

4.0 COMPLIANCE TESTING FOR OTHER POLLUTANTS

The referenced air permit also includes emission limitations and subsequent initial compliance testing requirements for various pollutants where the concentrations of these pollutants will not be determined during the aforementioned performance testing program. Rather, the referenced air permit provides alternate means and/or methods of determining these concentrations. Where requested by FDEP, pollutant concentrations will be converted into emission rates using the

applicable conversion equations. Volumetric flow rates achieved during the performance testing program will be used in order to compare the measured pollutant concentrations to the stated emission limitations as prescribed in the referenced air permit. The subject pollutants and the corresponding proposed test methods are as follows:

4.1 Sulfur Dioxide (SO₂)

For natural gas fuel, natural gas supplier data indicating the sulfur content of the natural gas via fuel analysis will be submitted. ASTM D1072-80, D3031-81, D4084-82, or D3246-81 (or equivalent) is the required method for determining the sulfur content of the natural gas fuel. Analysis responsibilities and custom monitoring schedules performed and agreed upon pursuant to 40 CFR Part 60, New Source Performance Standard (NSPS) Subpart GG, §§60.334(b) and 60.335(e) will be made between Seminole Electric and FDEP personnel under separate cover.

The sulfur content of the No. 2 fuel oil will also be submitted. ASTM D4294 (or equivalent) is the required method for determining the sulfur content of the fuel oil. The maximum sulfur content of the fuel oil shall not exceed 0.05 percent by weight. Compliance will be demonstrated in accordance with the requirements of 40 CFR Part 60, §60.334(b).

The sulfur contents of the natural gas and No. 2 fuel oil will be performed by a separate testing contractor (e.g., fuel(s) vendor).

4.2 Beryllium and Arsenic

Trace elemental concentrations of beryllium and arsenic via fuel analysis will be tested using solid waste regulations SWC 846 Method 7090/91 and Method 3040. Beryllium and arsenic concentrations will be determined for No. 2 fuel oil only. As is the case for sulfur content, any fuel analyses will be performed by a separate contractor.

5.0 TEST EQUIPMENT CALIBRATIONS

Test equipment will be calibrated before and/or during use in the field. Interference checks and response time checks will be performed on each monitor (as applicable) and the entire monitor sampling systems before field use. An NO to NO₂ converter efficiency test will be performed on-site with the procedures described in §5.6.1 of Method 20 (RM 20).

6.0 TEST REPORTS

Upon completion of the test program, a preliminary report summarizing the test results will be generated for Seminole Electric internal review prior to drafting the final report. The final report will include all field test data, process data, emissions calculations, calibration data, test method descriptions, stack information, and laboratory results. Two copies of the final test report will be submitted to the Florida Department of Environmental Protection (FDEP) for review.

APPENDIX A

PERFORMANCE TEST CONTACT LIST