Progress Energy

September 10, 2010

Mr. Jeffrey Koerner, P.E.
New Source Review Section
Bureau of Air Regulation/Division of Air Resource Management
Florida Department of Environmental Protection
2600 Blair Stone Road, MS 5500
Tallahassee, Florida 32399-2400

Re: Concurrent Processing of Revisions to TV and AC Permits
University of Florida Cogeneration Facility
Facility ID No: 0010001; Alachua County, FL

Dear Mr. Koerner:

This letter serves to transmit the Florida Power Corporation, d/b/a Progress Energy Florida, Inc (PEF) application for concurrent processing of revisions to the Title V (TV) and air construction (AC) permits for the above-referenced facility. Enclosed are an original and three copies of the air application package. This application is submitted following a pre-application meeting with the Department, as well as other discussions and correspondence related to these permitting issues. Specifically, PEF is seeking revisions to the combustion turbine (CT) emission limits for CO and NOx, as well as the compliance testing requirements for the duct burner (DB)

As discussed previously with the Department, a summary of the requested changes to the CO and NO_x limits for the University of Florida Cogeneration Facility is included in the following paragraphs. As you may recall, the UF Cogen Facility is requesting an increase in the CO concentration limit from the current 31.6 ppmvd, corrected to 15% O_2, to 33.6 ppmvd, corrected to 15% O_2, and the corresponding mass emission rate limit from 29.9 lbs/hour to 31.7 lbs/hour. In addition, based on a correction in the PSD avoidance analysis submitted as an integral part of the application for Permit No. 0010001-003-AC and received by the Department on January 29, 2001, PEF is also requesting an increase in the tons per year (TPY) limit for CO and NO_x from the CT while retaining the short-term NO_x emission limits.

Furthermore, as previously communicated to the Department, the UF Cogen Facility has some very real concerns with respect to complying with the DB testing requirements as stated in the recently renewed TV permit (Permit No. 001-0001-009-AV). These concerns are related to the infrequent use of the duct burners and the typical heat input rates when they do operate (i.e., the testing at maximum capacity requirement). The result is that it will be extremely difficult to comply with the DB testing requirements, given the notification requirement and/or the required testing within fifteen (15) days of exceeding a limit established by a test conducted at a reduced heat input rate.

In addition, the facility would like to revise or clarify some of the language included in the current permit. Some of these changes were requested during the permit renewal process, but the Department indicated these requested revisions/clarifications required concurrent processing of the air construction permit.

Therefore, PEF requests revisions/clarifications to the UF Cogen Facility's TV and AC permits to reflect requested changes to the CO and NOx emission limits and to the DB testing requirements, as follows:

1. Revisions to the CO and NOx emission limits, which are requested due to a correction in the previously determined PSD baseline, as well as the mischaracterization of the lower revised CO value as a BACT limit.

   a. Correction to the previous PSD analysis for CO and NO_x.

      In order to provide additional background for this discussion, a permitting history has been summarized and is included as Attachment 1 to this application package. The PSD analysis submitted to the Department in January of 2001 indicated that, to avoid PSD/NSR, restrictions on operating hours were necessary given the allowable NO_x mass emission rate and the applicable 40 TPY significant emission rate (SER) threshold. The baseline emissions for this pollutant were determined by selection of a two year period of 1999-2000, which provided a baseline NOx value of 101.5 TPY. The addition of 39.5 TPY (i.e., less than the 40 TPY SER) to the NOx baseline resulted in a permitted NOx limit of 141 TPY. With the allowable short-term limit of 39.6 lb/hr (at 49 °F), this equated to 7,122 hours per year, however, at the average ambient temperature of 63 °F, the NO_x lbs/hr value is 39.1 lbs/hr, equivalent to 7,211 hrs/year based on the 141 TPY NO_x limit. In fact, the application submitted in 2001 suggested that an inlet temperature of 63 °F (i.e., 39.1 lb/hr) was appropriate, as it represented the average inlet air temperature during calendar year 2000. Inlet cooling is an integral part of the system and suggests that this annual average value could be maintained.

      For CO, the annual mass emission limit appears to have been determined by using the same baseline time period (1999-2000 calendar years), resulting in 31.35 TPY. The associated CO annual emission limit of 127.5 TPY appears to have been obtained by multiplying the same allowable operating hours assumed under the NOx limit (i.e., 7,122 hours/year) and the 35.8 lbs/hour (at 49 °F) emission rate. Subtracting the CO baseline annual emissions of 31.35 TPY results in a proposed increase of 96.1 TPY, which is below the SER of 100 TPY.

      The facility subsequently requested an increase in hours of operation. The permitting approach assumed that increasing the operating hours under the same TPY CO cap would require a reduction in the hourly mass emission rate and the corresponding CO concentration limit. Therefore, increasing the operating hours for the CT to 8,541 hours/year and 219 hours/year while combusting natural gas and No. 2 fuel oil, respectively, resulted in a reduction in the hourly mass emission rate to 29.9 lbs/hour and the corresponding CO concentration limit to 31.6 ppmvd, corrected to 15% O_2. As an aside, the LM6000-ESPRINT combustion turbine is not equipped to fire No. 2 fuel oil; therefore, only natural gas is fired.

In hindsight, the two-year period of 1996-1997 should have been utilized for the NO_x emission baseline, resulting in a revised annual NOx baseline of 116.85 TPY. Adding the 39.5 TPY SER would result in 156.35 TPY as an annual NO_x mass emission limit from the CT. Applying the hourly NOx mass emission rate of 39.6 lbs/hour to the 156.35 TPY value results in an annual hourly operation limit of 7,897 hours/year; however, the annual hours of operation limit based on NOx is moot since the facility determines NOx compliance via CEMS. In summary, if NOx emissions were the only regulated pollutant and it remained low enough, as determined by CEMS, the facility could operate continuously. Therefore, the NOx mass emissions should not establish the annual hours of operation limit and thereby indirectly limit the SER increase in annual CO mass emissions below 99.5 TPY.

To avoid PSD, the CO annual mass emission increase must remain below the SER of 100 TPY; therefore, if the CO mass emission increase is limited to 99.5 TPY, the CO annual mass emission limit should have become 130.85 TPY. Applying the CO hourly emission rate of 35.8 lbs/hour (at 49 °F) results in an annual limit of 7,310 hours/year on hours of operation.

Given these new annual mass emission values, the operation of the CT would be limited by the CO mass emission rate and concentration values to 7,310 hours/year. However, it could be argued that the mass emission rate at 59 °F (i.e., 34.1 lb/hr) is more appropriate for back-calculating the annual operating hours. In fact, the application submitted in 2001 suggested that an inlet temperature of 63 °F (i.e., 31.3 lb/hr) was appropriate as it represented the average inlet air temperature during calendar year 2000. When applied to the annual mass emission limit of 130.85 TPY, the resulting annual allowable hours of operation are 7,674 hours/year (based on 34.1 lb/hr) and 8,361 hours/year (based on 31.3 lb/hr). If the facility utilizes a minimum of three weeks (i.e., 504 hours) for outages during the course of any calendar year, this is equivalent to 8,256 hours/year of operation and results in an hourly mass emission rate of 31.7 lb/hour at 59 °F, with a corresponding concentration of 33.6 ppmvd, corrected to 15% O_2. The Department could justify a permit revision to this requested annual operating limit of 8,256 hours/year by either accepting the revised 1999-2000 baseline, or by agreeing that the basis for the calculation is 31.3 lb/hr (i.e., an annual average inlet temperature of 63 °F).

b. In addition, the current concentration and mass emission rate limits of 31.6 ppmvd corrected to 15% O_2 and of 29.9 lbs/hr, respectively were not a reflection of Best Available Control Technology (BACT) for this make and model of CT. Rather, this reduction in the CO concentration limit and hourly mass emission rate were simply implemented to increase the hours of operation from 7,122 hours per year to 8,541hours per year without increasing the annual CO mass emissions and not due to any advances in the NOx or CO control technology for the CT.

The correction of previous assumptions in CO and NOx emissions permitting based on the arguments presented above result in the annual mass emission limits for NO_x and CO from the CT alone becoming 156.35 TPY and 130.85 TPY, respectively. In addition, the CO concentration limit would increase to 33.6 ppmvd and 31.7 lbs/hour with a limit on hours of

operation of 8,256 hours/year. The NO_x short-term basis of limit (i.e., ppmvd and lbs/hr) would remain the same.

2. Regarding the difficulties inherent for testing of emissions from the DB, PEF proposes the following for Department consideration:

   a. Elimination of the requirement to conduct separate testing for CO emissions from the DB - As further background for this discussion, Attachment 2 is included in this application package to provide the DB operating summary. The CT exhaust is routed through the Heat Recovery Steam Generator (HRSG), which is employed to convert the waste heat from the CT into steam. This steam is supplied to the University of Florida and Shands Hospital Systems. It is important to note that the DB cannot be operated without operating the CT and if the CT is operating the HRSG is generating steam. However, there is not always a demand for steam equivalent to the quantity continuously generated by the HRSG when the CT is operating. When no steam demand exists, or there is less steam demand than the HRSG generates, the steam is "dumped" or vented to the atmosphere through a steam vent. In the event that steam demand is greater than that generated by the CT/HRSG combination, additional heat energy is supplied by the DB to the HRSG to generate additional steam. PEF engineers have determined that, due to the current design and construction of the steam vent, the generation of additional steam by the DB, without adequate steam demand, cannot be conducted safely.

      In addition, the CT and DB exhaust gases are generated, combine and exit through the same stack and the only manner in which to quantify the emission from the DB is to determine the emissions from the CT operating alone and then determining emissions from the CT and DB operating concurrently. Therefore, emissions attributed to the DB are determined indirectly by the difference in emissions from the two modes of operation – CT plus DB and CT only – adding yet another level of complexity to the DB stack testing scenario.

      Recall the DB is only operated when the steam demand is high, which corresponds to low ambient temperatures. PEF has concerns regarding compliance with the 15-day notification requirement for compliance tests contained in Rule 62-297.310(7)(a)9, F.A.C. simply because predicting the arrival of cold days more than five days in advance is difficult or impossible with any degree of accuracy. In the event that conditions during compliance testing, including associated steam demand, limited the operation of the DB to 110% of the heat input at which it was tested, PEF has additional concerns regarding complying with providing proper notification within 15 consecutive days after operating the unit at a higher rate per Rule 62-297.310(2), F.A.C.

      PEF is also submitting two emission test summaries (Attachment 3- DB Emission Testing Summary) while the DB was operating that demonstrate that the DB contributed very little, if any, to the overall CO and NOx emissions. Moreover, the GE LM6000-ESPRINT CT is designed as a lean-burn combustion system. Specifically, there is excess air above the stoichiometric ratio of air introduced into the combustion zone with the fuel. Logically, the introduction of excess air into the DB combustion zone should facilitate the combustion of any CO that is produced as a result of incomplete combustion from the DB and CT in the HRSG.

This CO emissions trend is observed throughout the industry during stack testing of DB systems at similar units. PEF is aware of additional test data from other similar facilities that demonstrate the same trend and can supply this information to the Department if requested.

Finally, based on operation during the last three calendar years (2007 through 2008) the DB did not operate at all for approximately 73 percent of the time. Furthermore, the DB operated at a very low heat input rate of 20 to 30 mmBtu/hour approximately 21 percent of the time. This means that approximately 94 percent of the time, the DB either did not operate or operated at a rate less than or equal to about 30 mmBtu/hr compared to its rated capacity of 187 mmBtu/hr (Attachment 2, tabular summary).

In conclusion, whereas the NO_x from the CT/DB is being monitored by CEMS, PEF does not believe that testing the DB for CO emissions is warranted or provides useful data.

3. Revisions/Clarifications to TV and AC Permit Conditions – See Application Form, Attachment 4

If you have any questions, please contact Dave Meyer at Dave.Meyer@pgnmail.com or (727) 820-5295, or Chris Bradley at (727) 820-5962 or Chris.Bradley@pgnmail.com.

Thanks in advance for your time and effort in considering these important requested revisions to the associated University of Florida Cogeneration Facility permits.

Best regards,

Wilson B. Hicks, Jr., P.E.
Plant Manager & Responsible Official

Attachments

cc: Mr. Robert Bull, Jr., P.E. – Permitting Engineer/BAR
Mr. Jonathan Holtom, P.E. – Title V Administrator/BAR
Ms. Mary Alford, P.E. – Facility EHSS Staff
Mr. Scott Osbourn, P.E., Golder Associates

ATTACHMENT 1

UNIVERSITY OF FLORIDA
CO-GENERATION FACILITY

SUMMARY OF PERMITTING HISTORY

University of Florida Co-Generation Facility
Summary of Permitting History

PSD Permit No. PSD-FL-181 & initial Air Construction Permit No. AC01-204652: Issued on August 17, 1992 authorized the construction of a 43 MW co-generation facility at the University of Florida, in part, to replace Boilers Nos. 1, 2 & 3. The permit expired on December 31, 1994. Highlights include

1. A Combustion Turbine (CT) in conjunction with a Heat Steam Recovery Generator (HRSG) and duct burner was installed to replace three (3) boilers. The Ct was a LM6000 from General Electric (GE) and the HRSG was by Deltak and included a Duct Burner manufactured by Coen.

2. PSD analysis indicated that the BACT was applicable to carbon monoxide (CO).

3. The CO limit for the

    a. combustion turbine was 42 ppmvd on gas (BACT & basis of limit), 38.8 lbs/hr and 158 TPY. Limited to 8,147 hours/ year on natural gas.

    b. duct burner was 0.15 lb/mmBtu (BACT & basis of limit), 28.1 lbs/hour and 36.9 TPY. Limited to 2,628 hours/year of operation.

4. Combustion turbine was authorized to operate up to 219 hour/year on No. 2 fuel oil; however, and additional 1.9 hours/year operation on natural gas was allowed each 1.0 hour/year that fuel oil is not burned up to 416 hours (i.e., 219 hours X 1.9). Natural gas combustion emission limits were to be "adjusted accordingly".

5. Total NOx emissions for the facility were capped at 194.3 TPY.

Permit Nos. PSD-FL-181(A)/AC01-204652: Issued on September 11, 1997 as an amendment to the original PSD and AC permits. Highlights include

1. The lbs/hr limit for NOx from the combustion turbine was increased from 35.0 to 39.6 lbs/hr. This action was taken to allow for a requested increase in heat input to the CT at ambient temperatures near 45 °F and a corresponding increase in short-term NOX emission in lbs/hour). There was no corresponding increase in the annual NOx emissions in TPY authorized.

Permit No. 0010001-001-AV: Issued on January 01, 2000 as the initial Title V permit. Highlights include

1. The basis of limit for CO for the combustion turbine operating on natural gas remains at 42 ppmv (BACT) and the allowable limits are 38.8 lbs/hr and 158.0 TPY.

2. The basis of limit for the CO from the duct burner remains at 0.15 lb/mmBtu (BACT) and the allowable limits are 28.1 lbs/hr and 36.9 TPY.

3. The facility NOx emissions cap remained at 194.3 TPY. The combustion turbine is limited to 39.6 lbs/hr and 142.7 TPY with the basis of these limit being 25 ppmvd. Limits are based on a 30-day rolling average.

Permit No. 0010001-002-AC: This permit was never issued and no documents are posted on the DEP's "Permit Document Search" webpage.

Permit No. 0010001-003-AC: Issued on May 18, 2001 authorized the replacement of the 43 MW GE LM6000 combustion turbine with a new 48 MW model incorporating the SPRay INTercooling ("SPRINT") technology. Due to the combustion characteristics of the replacement combustion turbine, CO emission will be lowered and limited to 36 ppmvd for natural gas. This results in a decrease in the allowable CO emission from 158 TPY to 127.5 TPY. Highlights include

1. Authorized the replacement of the GE LM6000 Combustion turbine with the GE LM6000-SPRINT model.

2. PSD review and a BACT determination were NOT REQUIRED for this project since the net emissions increases are less than the PSD Significant Emission Rate (SER) for all pollutants.

3. The combustion turbine/duct burner operation at maximum firing rates shall be limited to 7,122 hours per year (to prevent retroactive PSD applicability for NOx under PSD-FL-181 by reaching the 40 tons per year PSD applicability threshold). The turbine/duct burner may operate at lower than maximum rates for more hours per year provided that the annual fuel consumption limitations are not exceeded, i.e., total annual fuel usage for the combustion turbine and the duct burner combined shall not exceed 3.48 trillion Btu.

4. Hours of Operation/Fuel Usage Limitations: Combustion turbine/duct burner operation at maximum firing rates shall be limited to 7,122 hours per year (to prevent retroactive PSD applicability for NOx under PSD-FL-181, pursuant to Rule 62-212.400(5), F.A.C., by reaching the 40 tons per year PSD applicability threshold). The turbine/duct burner may operate at lower than maximum rates for more hours per year provided that the annual fuel consumption limitations are not exceeded and that facility-wide NOx emissions do not exceed 194.3 TPY. The total annual fuel usage for the combustion turbine and the duct burner combined shall not exceed 3.48 trillion BTU (includes up to 635,100 gallons No. 2 fuel oil fired in the turbine). The annual fuel usage by the duct burner is limited to 519.5 million cf natural gas.

5. PSD analysis was conducted and the NOx emission increase was 39.5 TPY; below the Significant Emission Rate (SER) of 40 TPY.

6. Total NOx emissions from the CT/HRSG configuration were capped at 141 TPY and 25 ppmvd on a 30-day rolling average. The 141 TPY NOx cap on the CT/HRSG s was at the request of Florida Power Corporation (FPC) to avoid PSD.

7. PSD analysis was conducted and the CO emission increase was 96.1 TPY; below the Significant Emission Rate (SER) of 100 TPY.

8. Total CO emissions from the CT/HRSG configuration shall not exceed 36 ppmvd (decreased from 42 ppmvd), 35.8 lbs/hr (decreased from 38.8 lbs/hr) and 127.5 TPY (decreased from 158.0 TPY). This was at the request of Florida Power Corporation (FPC) to avoid PSD.

9. CO emissions from the DB shall not exceed 0.15 lb/mmBtu, 28.1 lbs/hr and 39.6 TPY.

Permit No. 0010001-004-AC: Requested modification of 0010001-003-AC. Highlights include

1. Heat input for the combustion turbine while firing natural gas was increased from the current 392 mmBtu/hour to 408 mmBtu/hour; both heat inputs are reference to 59 °F and the Lower Heating Value (LHV) of the natural gas. The permit now only references "The values indicated on the turbine manufacturer's heat input vs. power output curve attached to this permit (Attachment C)."

2. The combustion turbine limit on total NOx emissions remains at 141 TPY.

Letter Amendment to Permit No. 0010001-004-AC: Issued on March 27, 2003 authorized the extension of permit expiration date for permit No. 100010001-003-AC, extending the expiration date from December 31, 2002 to December 31, 2003.

Permit No. 0010001-006-AC: Issued on October 9, 2003 and amended permit No. 0010001-004-AC. Essentially Progress Energy requested a revision to reduce the combustion turbine short-term CO limits to avoid New Source Review (NSR). Highlights include

1. CO emissions from the CT shall not exceed 31.6 ppmvd (decreased from 36 ppmv), 29.9 lbs/hr (decreased from 35.8 lbs/hr) and 127.5 TPY (remained unchanged). This appears to be the result of a request for increase in annual hours of operation; that is,

   (127.5 TPY)(1 ton/2,000 lbs) / (8,541 hours/year) = 29.86 lbs/hr = 29.9 lbs/hr

2. The combustion turbine and duct burner are allowed to operate continuously (i.e., 8,760 hrs/yr) while firing natural gas. At the maximum firing rate, the CT is limited to firing No. 2 fuel oil for 219 hours/year; that is,

   (8,760 hours/year – 8,541 hours/year) = 219 hours/year

3. Remaining changes are associated with NOx emissions.

Permit No. 0010001-005-AV: This revision to the Title V permit was issued January 05, 2004. The revision included the incorporation of the following permits into the Title V Air Operating Permit:

1. Permit No. 0010001-003-AC
2. Permit No. 0010001-004-AC

3. Permit No. 0010001-006-AC

Permit No. 0010001-007-AV: Renewal of Permit number 0010001-005-AV was issued with an effective date of January 01, 2005. Highlights include

1. The allowable CO limits for combustion turbine remain unchanged at 31.6 ppmv, 29.9 lbs/hr and 127.5 TPY.

2. The allowable CO limit for duct burner remains at 0.15 lb/mmBtu, 28.1 lbs/hr and 36.9 TPY.

3. The combustion turbine and duct burner continue to be allowed to operate continuously (i.e., 8,760 hrs/yr) while firing natural gas. At the maximum firing rate, the CT is limited to firing No. 2 fuel oil for 219 hours/yr.

4. For "Permitted Capacity" the permit references a heat input vs. power output curve; specifically, "....the attached GE Curves Corrected for Site Conditions"

Permit No. 0010001-008-AV: Revision of Permit No. 0010001-007-AV was issued on March 24, 2009 and was issued to include the requirements and conditions of the Clean Air Interstate Rule (CAIR) in the Title V Operating Permit.

Permit No. 0010001-009-AV: Renewal of Permit No. 0010001-008-AV with an effective date of January 01, 2010; this is the current Title V permit the facility is operating under. Highlights include:

1. The combustion turbine and duct burner continue to be allowed to operate continuously (i.e., 8,760 hrs/yr) while firing natural gas. At the maximum firing rate, the CT is limited to firing No. 2 fuel oil for 219 hours/yr.

2. The allowable CO limit for combustion turbine remains at 31.6 ppmv, 29.9 lbs/hr and 127.5 TPY.

3. The allowable CO limits for duct burner remain unchanged at 28.1 lbs/hr and 36.9 TPY. The value of 0.15 lb/mmBtu returns to being the basis of limit.

Combustion Turbine Hourly Emissions Rate Summary
University of Florida
Natural Gas Firing

Compound	Ambient Temp	55	66.3	71.1	105	MAX
	Inlet Temp	49	59	63.2	93.4	
	Load, %	Emissions for LM6000-PC-ESPRINT Turbine, lb/hr				lb/hr
NOx	100	39.6	39.6	39.1	32.9	39.6
CO	100	35.8	34.1	31.3	12.0	35.8
VOC	100	5.6	5.4	5.3	4.6	5.6
SO2	100	1.2	1.2	1.2	1.0	1.2
PM	100	3.0	3.0	3.0	3.0	3.0
Notes:	The average inlet temperature during the year 2000 was 63.2 °F					

Combustion Turbine Annual Emission Summary
University of Florida

Turbine	NOx	CO	VOC	SO2	PM	PM_{10}	Pb
	Emissions for One Combustion Turbine (tons/year) [1]						
GE LM6000-PC-ESPRINT, 49°F inlet, 8760 hr/yr[1]	173.4	156.8	24.5	5.3	13.1	13.1	0.000
GE LM6000-PC-ESPRINT, 49°F inlet, 7121hr/yr1	141.0	127.5	19.9	4.3	10.6	10.6	0.000
GE LM6000-PC-ESPRINT, 63.2°F inlet, 8760 hr/yr[2]	171.3	137.1	23.2	5.3	13.1	13.1	0.000
GE LM6000-PC-ESPRINT, 63.2°F inlet, 7210.5 hr/yr	141.0	112.8	19.1	4.4	10.8	10.8	0.000

[1]These annual emission estimates are based on worst case hourly emissions and unlimited operation, I.e., inlet temperature of 49°F and natural gas operation of 8760 hrs/year, 100% load.
[2]The average inlet temperature for the year 2000 was 63.2°F. Emissions are at 100% load.

ATTACHMENT 2

UNIVERSITY OF FLORIDA

CO-GENERATION FACILITY

DUCT BURNER OPERATING SUMMARY

(INCLUDING A TABULAR SUMMARY OF OPERATING RANGE)

University of Florida Co-Generation Facility
The "How, When & Why" of Duct Burner Operation

The facility typically operates the GE LM6000-SPRINT combustion turbine at approximately 95% of load at all times, with the exceptions being during start-ups, shutdowns, malfunctions and outages. The combustion turbine is exhausted through the heat recovery steam generator (HRSG) to generate steam for the University, hospitals and their associated facilities. The steam generated by the HRSG is provided on an as-needed basis; i.e., when the steam demand is present. If there is no steam demand or steam demand is less than the steam generated by the HRSG from the combustion turbine exhaust, the excess steam is "wasted" or vented. Therefore, the greatest quantity of steam is "wasted" or vented when ambient temperatures are the warmest.

Alternatively, the peak steam demand from the University, hospitals and associated facilities typically coincides when ambient temperatures are coldest. However, if the HRSG cannot meet the steam demand with steam generated solely from the combustion turbine exhaust, supplemental heat input is provided by the duct burner. In response to the steam demand, up to ten (10) different levels of burners will fire. Each level of burner either operates at 100% of its capacity or does not operate at all; there is no partial firing of individual burners or burner levels. Furthermore, the duct burner cannot operate independently of the combustion turbine; i.e., the facility is incapable of operating with just the duct burner firing, the combustion turbine must be fired in conjunction with the duct burner.

When steam demand requires firing of the duct burner the heat input (in mmBtu/hour) to the duct burner will fluctuate to control HRSG superheater outlet pressure; i.e., rise and fall, during any given time the duct burner is operating. This fluctuation or variation in heat input can be extensive. With the inherent limitations on the operation of the duct burner there are several obstacles to conducting testing that would meet the letter of Chapter 62 of the Florida Administrative Code (F.A.C.). The FAC requires operating the duct burner at 90% of the permitted heat input or limit the heat input to the duct burner by testing at a lower rate, thereby limiting the duct burner to 110% of the heat input at which it was tested. In addition, if the unit exceeds the self-imposed heat input limit, PEF is required by rule (62-297.310(2), F.A.C.) to conduct testing within 15 days of exceeding the testing-imposed heat input limit. This would require that the unit be re-tested within 15-days and to accomplish testing at the higher heat input would require a greater steam demand (i.e., typically colder temperatures) than operating mode during which the testing-imposed limit was exceeded. If the steam demand was less than required, it would require venting or "wasting" steam, burning fuel unnecessarily and generating unnecessary emissions. Further, the venting itself represents a safety issue In addition, providing appropriate test notifications would prove problematic given the inability to predict the weather and adequately schedule stack test teams. The result would be the reliance on enforcement discretion from the compliance authority regarding test notifications; PEF prefers not to rely on enforcement discretion and would prefer to address this situation through the permitting process.

TABLE 1

DUCT BURNER HEAT INPUT VS. PERCENT OPERATING TIME (FROM 0 MMBTU/HR TO 100 MMBTU/HR)

Percentage of Hours for Calendar Years 2007 through 2009	Range of Hourly Average Heat Input
73.24	0 mmBtu/hr
0.02	0.1 - 20.0 mmBtu/hr
22.66	20.1 - 40.0 mmBtu/hr
3.02	40.1 - 60.0 mmBtu/hr
0.92	60.1 - 80.0 mmBtu/hr
0.14	80.1 - 100.0 mmBtu/hr
100.00	Total Percentage of Hours

TABLE 2

DUCT BURNER HEAT INPUT VS. PERCENT OPERATING TIME (FROM 30 MMBTU/HR TO 40 MMBTU/HR)

Percentage of Hours for Calendar Years 2007 through 2009	Range of Hourly Average Heat Input
20.08	20.1 - 30.0 mmBtu/hr
2.58	30.1 - 40.0 mmBtu/hr
22.66	Percentage of Total Time operating at 20.1 - 40.0 mmBtu/hr

TABLE 3

DUCT BURNER HEAT INPUT VS. PERCENT OPERATING TIME (FROM 20 MMBTU/HR TO 30 MMBTU/HR)

Percentage of Hours for Calendar Years 2007 through 2009	Range of Hourly Average Heat Input
15.55	20.1 - 25.0 mmBtu/hr
4.54	25.1 - 30.0 mmBtu/hr
20.09	Percentage of Total Time operating at 20.1 - 30.0 mmBtu/hr

ATTACHMENT 3

UNIVERSITY OF FLORIDA
CO-GENERATION FACILITY

DUCT BURNER EMISSIONS TESTING SUMMARY

ANNUAL PERMIT COMPLIANCE TEST REPORT

For

DUCT BURNER EMISSIONS

On a

COGENERATION UNIT CONSISTING OF A COMBINED-CYCLE GENERAL ELECTRIC LM 6000 PC SPRINT COMBUSTION TURBINE AND COEN DUCT BURNER SYSTEM

At the

UNIVERSITY OF FLORIDA COGENERATION PLANT

In

GAINESVILLE, ALACHUA COUNTY, FLORIDA

Prepared for the

FLORIDA POWER CORPORATION

October 2001

Cubix Job No. 6626-10

Prepared by

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INTRODUCTION

Emission testing was conducted on a combined-cycle 48-megawatt (MW) General Electric (GE) LM 6000 PC gas turbine generator set and associated duct burner system. The unit consists of a natural gas fueled combined-cycle combustion turbine directly coupled to a 60-Hertz generator. Combustion turbine exhaust is routed to a heat recovery steam generator (HRSG) that is equipped with a supplemental natural gas-fired Coen duct burner system. This cogeneration unit, used to generate both electrical power and process steam, is in service at the University of Florida Cogeneration Facility located in Gainesville, Alachua County, Florida. Florida Power Corporation (FPC), a Progress Energy Company, owns and operates this facility. Cubix Corporation, Southeast Regional Office conducted this testing on September 24th, 2001.

The purpose of this testing was to determine the status of annual compliance for duct burner emissions with the permit limits set forth by the Florida Department of Environmental Protection (FDEP) Title V Permit Number 0010001-001-AV. The tests followed the procedures set forth in 40 CFR 60, Appendix A, Methods 3a, 7e, 9, 10, and 19.

The combustion turbine exhaust was analyzed for oxides of nitrogen (NO_X), carbon monoxide (CO), and oxygen (O_2) using continuous instrumental monitors at a location prior to the duct burners. The combined combustion turbine and duct burner system exhaust was analyzed for CO and O_2 using continuous instrumental monitors at the HRSG stack. A certified observer determined visible emissions (VE) from the HRSG stack for the combined emissions. Additionally, the FPC continuous emissions monitoring system (CEMS) data for combined NO_X and CO_2 emissions were collected from the HRSG stack. Table 1 provides background data pertinent to these tests.

This test report has been reviewed and is approved for submittal by the following representatives:

Cubix Corporation | **Florida Power Corporation**

TABLE 1
BACKGROUND DATA

Owner/Operator:	**Florida Power Corporation** A Progress Energy Company 13th Avenue South, BB1A St. Petersburg, Florida 33701 Attn: J. Michael Kennedy, Air Program Supervisor (727) 826-4434 Phone (727) 826-4216 Facsimile Email: j-michael.kennedy@pgnmail.com
Testing Organization:	**Cubix Corporation, SE Regional Office** 3709 SW 42nd Avenue, Suite 2 Gainesville, Florida 32608 Attn: Leonard Brenner, Project Manager (352) 378-0332 Phone (352) 378-0354 Facsimile Email: lbrenner@cubixcorp.com
Test Participants:	**Florida Power Corporation** J. Michael Kennedy **Cubix Corporation** Leonard Brenner Roger Paul Osier
Test Dates:	September 24th, 2001
Regulatory Application:	The state regulations under Florida Department of Environmental Protection (FDEP) Title V Permit No. 0010001-001-AV apply.
Facility Location:	The FPC University of Florida Cogeneration Facility is located on Mowry Road at Building 82, University of Florida in Gainesville, Alachua County, Florida at postal code 32601 (UTM Coordinates: Zone 17, 369.4 km East and 3279.3 km North; Latitude: 29°38'23" North and Longitude: 82°20'55" West.)

Process Description:

A cogeneration unit, consisting of a combined-cycle combustion turbine (CT) and a heat recovery steam generator (HRSG) equipped with a supplemental duct burner system, is used to generate electrical power and process steam. The CT, a General Electric Model LM 6000 PC gas turbine generator with Enhanced Sprint System, consists of a single-shaft gas combustion turbine directly connected to a 60 Hz power generator. CT exhaust gases are routed to an HRSG to recover waste heat from the combustion process. A Coen duct burner system is installed in the HRSG stack to boost the heat in the system, thus increasing steam production. The facility is designed to provide natural gas fuel to the combustion turbine and duct burners. The turbine uses steam injection to control NO_X emissions. The duct burner system uses low-NO_X burners to control NO_X emissions.

Emission Sampling Points:

The combustion turbine has been designated in the permit as FDEP Emissions Unit (EU) ID No. 0010001-001-001. The combustion turbine emissions may be measured from one of two locations. The primary location is the HRSG stack. Four sample ports are located perpendicular to each other in the 117-inch diameter circular stack. However, these ports cannot be used to determine turbine emissions while the duct burner system is firing. The second location is the CT outlet. This consists of one port in the HRSG at a location prior to the duct burners and located near the center of the HRSG ductwork, see Appendix A for diagrams. Access to the sample ports was provided with a permanently installed platform and stairwell system.

The HRSG with the duct burner system has been designated in the permit as FDEP EU ID No. 0010001-001-002. Duct burner system emissions exhaust through the HRSG stack described above in combination with CT emissions, see Appendix A. Duct burner emissions were determined from the difference of the CT outlet emissions from the HRSG stack emissions. Access to the sample ports was provided with a permanently installed platform stairwell system, and ladder system.

Test Methods:

EPA Method 3a was used to measure HRSG stack and Duct Burner inlet oxygen (CO_2) concentrations.

EPA Method 7e was used to measure Duct Burner inlet oxides of nitrogen (NO_X) concentrations.

EPA Method 9 was used to determine HRSG stack visible emissions (VE) measurements determined as opacity from a certified observer.

EPA Method 10 was used to measure carbon monoxide (CO) concentrations.

EPA Method 19 was used for calculation of stack flow and pollutant mass emission rates.

Facility CEMS provided HRSG stack NO_X and carbon dioxide (CO_2) emissions

SUMMARY OF RESULTS

Florida Power Corporation owns and operates the University of Florida Cogeneration Facility in Gainesville, Florida. At this facility a cogeneration unit, consisting of a combined-cycle combustion turbine and HRSG with duct burner system, is used to generate electrical power and process steam. The State of Florida designates the combustion turbine as FDEP EU ID No. 0010001-001-001. The State of Florida designates the duct burner system as FDEP EU ID No. 0010001-001-002. Exhaust emissions from these units are the subject of this report.

The test matrix consisted of determining duct burner (DB) system emissions. The tests included measurements of HRSG stack emissions and CT outlet emissions. DB emissions were determined as the difference of the CT outlet emissions from the HRSG stack emissions. Cubix conducted three test runs at the maximum achievable DB system operational load. The CT was operated at a steady load during these tests. The HRSG stack was measured for CO and O_2 concentrations using continuous instrumental monitors. Additional HRSG stack measurements included NO_X and CO_2 concentrations using the facility CEMS. The CT outlet, prior to the DB system, was measured for NO_X, CO, and O_2 concentrations using continuous instrumental monitors. The test runs were 1 hour in duration for all gaseous constituents. A one-hour VE test was conducted coincident with one of the test runs.

Table 2, the executive summary, signifies the performance for the DB system during the testing. These performance results are an average of the three test runs. These emissions are compared to the applicable environmental regulations.

TABLE 2
Executive Summary

Parameter	FDEP EU ID No. 0010001-001-002 Duct Burner System	FDEP Permit Limits
Duct Burner Heat Input (MMBtu/hr, LHV)	107.6	187.0
Load (% of Capacity as Heat Input, LHV)	57.6%	na
NO_X (lbs/hr)	0.809	18.7
NO_X (lbs/MMBtu)	0.00668	0.10
NO_X (tons/yr, assumes 2628 hours per year)	1.06	24.6
CO (lbs/hr)	10.4	28.1
CO (lbs/MMbtu)	0.0873	0.15
CO (tons/yr, assumes 2628 hours per year)	13.7	36.9
Visible Emissions (% opacity)	0%	10%

Table 3 presents a detailed summary of the emissions testing. This tabular summary contains all pertinent operational parameters, CEMS data, ambient conditions, measured emissions, corrected concentrations, and calculated emission rates. NO_X emissions are reported in units of parts per million by volume (ppmv) on a dry basis, ppmv corrected to 15% excess O_2 for the CT only, pounds per hour (lbs/hr), and pounds per million British thermal units (lbs/MMBtu) of fuel burned for the DB system only. CO emissions are reported in units of ppmv, dry basis, ppmv corrected to 15% excess O_2 for the CT only, lbs/hr, and lbs/MMBtu of fuel burned for the DB system only.

Volumetric flow and mass emission rates were determined by stoichiometric calculations (EPA Method 19) based on measurements of diluent gas O_2 concentrations, published "F-factors", fuel heating values determined from fuel composition, and unit fuel flow rates. Examples of emission rate calculations and other calculations necessary for the presentation of the results of this section are contained in Appendix B.

A VE observer certified per EPA Method 9 by Eastern Technical Associates of Raleigh, North Carolina, performed visible emission observations on the HRSG stack. A one-hour visible emissions test run was conducted per permit requirements. VE were an average of 0% opacity in the highest six-minute average for each test and no VE greater than 0% opacity was observed during the tests.

Appendix A contains field data sheets and stack diagrams. Appendix B contains examples of all calculations necessary for the reduction of the data presented in this report. Appendix C contains the fuel analysis supplied by FPC and Cubix's fuel calculation worksheet. Quality assurance activities are documented in Appendix D. Certificates of calibrations are contained in Appendix E of this report. Appendix F contains the records of logged data in one-minute intervals used to record the NO_X, CO, and O_2 concentrations; it also includes a running and final average of raw data. Appendix G contains the "Visible Emissions Observation Forms" and the observer certifications. Appendix H contains the operational data and CEMS data provided by FPC during the test runs. The FDEP facility permit is presented in Appendix I for reference purposes.

TABLE 3
Summary of Results
Duct Burner Compliance Testing

Company: Florida Power Corporation
Plant: UF Cogeneration Facility
Location: Gainesville, Florida
Technicians: LJB, RPO
Sources: Unit 001, a GE LM6000 PC Combustion Turbine
Unit 002, Coen Duct Burner System

Test Number	**002-C-1**	**002-C-2**	**002-C-3**		
Date	9/24/01	9/24/01	9/24/01		
Start Time	9:35	11:05	12:20		**FDEP**
Stop Time	10:35	12:05	13:20		**Permit**
Unit Operational and CEMS Data				*Averages*	**Limits**
Generator Active Power (MW)	36.51	36.21	36.22	***36.31***	
Duct Burner Load (% of full load = 187.0 MMBtu/hr, LHV)	55.1%	58.6%	59.0%	***57.6%***	
CEMS NO_X (ppmv, dry basis)	18.364	18.808	18.893	***18.688***	
CEMS CO_2 (% volume, dry basis)	4.264	4.321	4.334	***4.306***	
CEMS NO_X (ppmv @ 15% excess O_2)	14.67	14.66	14.70	***14.68***	
Unit Fuel Data (Natural Gas)					
Fuel Heating Value (Btu/lb, Higher Heating Value)	1041	1041	1041	***1041***	
O_2 "F_d Factor" (DSCFex/MMBtu @ 0% excess air)	8710	8710	8710	***8710***	
Duct Burner Fuel Flow (kSCFH)	110.08	117.08	117.83	***115.0***	
Duct Burner Heat Input (MMBtu/hr, HHV)	114.6	121.9	122.6	***119.7***	
Turbine Fuel Flow (kSCFH)	349.3	347.8	347.0	***348.0***	
Turbine Heat Input (MMBtu/hr, HHV)	363.6	362.0	361.1	***362.2***	
Total (Turbine + DB) Heat Input (MMBtu/hr, HHV)	478.1	483.9	483.7	***481.9***	
Ambient Conditions					
Atmospheric Pressure ("Hg)	29.86	29.86	29.84	***29.85***	
Temperature (°F): Dry bulb	82.8	86.4	90.2	***86.4***	
(°F): Wet bulb	77.1	77.9	78.2	***77.7***	
Humidity (lbs moisture/lb of air)	0.0183	0.0182	0.0176	***0.0180***	
Combustion Turbine Measured Emissions					
NO_X (ppmv, dry basis)	18.17	18.23	18.23	***18.21***	
CO (ppmv, dry basis)	10.75	10.74	10.62	***10.70***	
O_2 (% volume, dry basis)	15.17	15.25	15.22	***15.21***	
HRSG Stack Measured Emissions					
CO (ppmv, dry basis)	23.69	22.82	22.28	***22.93***	
O_2 (% volume, dry basis)	13.39	13.35	13.39	***13.38***	
Volumetric Flow Rates (EPA Method 19)					
Turbine O_2 "F_d Factor" (SCFH, dry basis)	1.156E+07	1.166E+07	1.157E+07	***1.160E+07***	
HRSG Stack O_2 "F_d Factor" (SCFH, dry basis)	1.160E+07	1.167E+07	1.173E+07	***1.166E+07***	
Turbine Emission Rates (via M-19 O_2 "F-factor")					
NO_X (ppmv, dry @ 15% excess O_2)	**18.7**	**19.0**	**18.9**	***18.9***	**25.0**
NO_X (lbs/hr, from Turbine)	**25.1**	**25.4**	**25.2**	***25.2***	**39.6**
CO (ppmv, dry @ 15% excess O_2)	**11.1**	**11.2**	**11.0**	***11.1***	**36.0**
CO (lbs/hr, from Turbine)	**9.03**	**9.11**	**8.94**	***9.03***	**28.8**
Duct Burner Emission Rates (via M-19 O_2 "F-factor")					
NO_X (lbs/hr, from Duct Burner)	**0.354**	**0.814**	**1.26**	***0.809***	**18.7**
NO_X (lbs/MMBtu, from Duct Burners)	**0.00309**	**0.00668**	**0.0103**	***0.00668***	**0.10**
CO (lbs/hr, from Duct Burner)	**10.9**	**10.3**	**10.1**	***10.4***	**28.1**
CO (lbs/MMBtu, from Duct Burners)	**0.0956**	**0.0842**	**0.0820**	***0.0873***	**0.15**

PROCESS DESCRIPTION

Florida Power Corporation owns and operates the University of Florida Cogeneration Facility in Gainesville, Florida. A cogeneration unit consists of a combustion turbine connected to a HRSG with a supplemental DB system. This unit produces both electrical power and process steam. Emission testing was conducted on the unit to determine the compliance status of the DB system with state regulations. This section of the test report provides a brief description of the cogeneration unit.

This cogeneration unit is designed to produce a nominal 48 MW of electrical power. The main body of the CT section consists of single shaft General Electric Frame LM 6000 PC gas turbine generator set directly coupled to a 60 Hz synchronous generator. The CT is equipped with evaporative coolers to drive the inlet air temperature down and an Enhanced Sprint System, Model 191-315, to inject water mist into the turbine air inlet. This ancillary equipment increases power output of the CT. The FDEP permitted capacity for the CT section is 399 MMBtu/hr based upon the lower heating value (LHV) of heat input firing with natural gas fuel. The CT is also permitted to operate while firing with No. 2 distillate fuel oil but does not do so at this time. The CT uses steam injection to control NO_X emissions. The State of Florida designates the CT section of this cogeneration unit with FDEP E.U. ID No. 0010001-001-001.

The cogeneration unit is also designed to produce process steam used by the CT and other facilities at the University of Florida. The CT exhaust is routed to a heat recovery steam generator. The HRSG is equipped with a supplemental Coen duct burner system to maximize steam production. The FDEP permitted capacity for the DB section is 187 MMBtu/hr (LHV) of heat input firing with natural gas fuel. The Coen DB system uses low-NO_X burners to control NO_X emissions. The State of Florida designates the DB section of this cogeneration unit with FDEP E.U. ID No. 0010001-001-002.

CT and DB exhaust gases are vented to the atmosphere through the HRSG stack that is a 92.5-foot tall circular stack. The sampling ports are approximately 29 feet (~ 3.0 stack diameters) downstream from the nearest flow disturbance, the HRSG outlet and approximately 10.5 feet (~ 1.1 stack diameters) upstream from the nearest flow disturbance, the stack outlet. Access to the stack was made available via a permanent steel frame platform equipped with a caged safety ladder and a stairwell system. The internal diameter of the stack at the sample port location was 117 inches. In addition, a sampling location in the beginning of the HRSG and before the DB system was used to sample CT only exhaust gases. This 2-inch diameter sample port was located near the center of the HRSG duct. Access to this

sample location was made available via a permanent steel frame platform equipped with a stairwell system.

FPC personnel obtained operational data from control panel instrumentation. Data was collected from the control system in approximate 15-minute intervals and averaged over each test run. In addition, CEMS data was collected in one-minute intervals into an electronic file and averaged using a spreadsheet program over each test run. All operational data sheets are located in Appendix H.

UF Cogeneration Facility
New Coen Duct Burner
Emissions Tuning Results

Company: Florida Power Corporation
Plant: UF Cogeneration Facility
Location: Gainesville, Florida
Technicians: LJB, RPO
Sources: Unit 001, a GE LM6000 PC Combustion Turbine
Unit 002, Coen Duct Burner System

Test Number	**Step 0**	**Step 1**	**Step 2**	**Step 3**	**Step 4**	
Date	4/29/02	4/29/02	4/29/02	4/29/02	4/29/02	
Start Time	11:15	12:10	12:52	13:27	14:02	**FDEP**
Stop Time	11:30	12:24	12:59	13:40	14:14	**Permit**
Unit Operational and CEMS Data						**Limits**
Generator Active Power (MW)	45.9	46.0	45.9	46.2	46.1	
Duct Burner Load (% of full load = 187.0 MMBtu/hr, LHV)	0.0%	13.2%	23.3%	28.1%	39.4%	
Number of Burners Firing	0	2	4	4	6	
Unit Fuel Data (Natural Gas)						
Fuel Heating Value (Btu/lb, Higher Heating Value)	1041	1041	1041	1041	1041	
O_2 "F_d Factor" (DSCFex/MMBtu @ 0% excess air)	8710	8710	8710	8710	8710	
Duct Burner Fuel Flow (kSCFH)	0.0	26.3	46.6	56.1	78.6	
Duct Burner Heat Input (MMBtu/hr, HHV)	0.0	27.4	48.5	58.4	81.8	
Duct Burner Heat Input (MMBtu/hr, LHV)	0.0	24.6	43.6	52.5	73.6	
Turbine Fuel Flow (kSCFH)	420.6	419.3	418.8	421.0	418.5	
Turbine Heat Input (MMBtu/hr, HHV)	437.7	436.4	435.9	438.2	435.6	
Total (Turbine + DB) Heat Input (MMBtu/hr, HHV)	437.7	463.8	484.4	496.5	517.4	
Ambient Conditions						
Atmospheric Pressure ("Hg)	29.93	29.91	29.89	29.88	29.87	
Temperature (°F): Dry bulb	87.0	88.0	89.5	92.0	92.8	
(°F): Wet bulb	73.0	74.0	74.3	74.8	75.0	
Humidity (lbs moisture/lb of air)	0.0138	0.0144	0.0143	0.0141	0.0141	
Combustion Turbine Measured Emissions						
NO_X (ppmv, dry basis)	20.69	18.30	18.21	18.44	18.37	
CO (ppmv, dry basis)	15.60	22.94	23.13	22.44	22.48	
O_2 (% volume, dry basis)	14.76	14.74	14.71	14.70	14.70	
HRSG Stack Measured Emissions						
NO_X (ppmv, dry basis)	21.14	19.05	19.09	19.57	20.30	
CO (ppmv, dry basis)	15.62	24.70	28.31	27.26	26.09	
O_2 (% volume, dry basis)	14.65	14.33	14.00	13.82	13.48	
Volumetric Flow Rates (EPA Method 19)						
Turbine O_2 "F_d Factor" (SCFH, dry basis)	1.298E+07	1.290E+07	1.282E+07	1.286E+07	1.279E+07	
HRSG Stack O_2 "F_d Factor" (SCFH, dry basis)	1.275E+07	1.285E+07	1.278E+07	1.277E+07	1.269E+07	
Turbine Emission Rates (via M-19 O_2 "F-factor")						
NO_X (ppmv, dry @ 15% excess O_2)	**19.9**	**17.5**	**17.4**	**17.5**	**17.5**	**25**
NO_X (lbs/hr, from Turbine)	**32.1**	**28.2**	**27.9**	**28.3**	**28.0**	**39.6**
CO (ppmv, dry @ 15% excess O_2)	**15.0**	**22.0**	**22.0**	**21.4**	**21.4**	**36**
CO (lbs/hr, from Turbine)	**14.7**	**21.5**	**21.6**	**21.0**	**20.9**	**28.8**
Duct Burner Emission Rates (via M-19 O_2 "F-factor")						
NO_X (lbs/hr, at HRSG Stack)	**32.2**	**29.2**	**29.1**	**29.8**	**30.8**	
NO_X (lbs/hr, from Duct Burner)	**na**	**1.05**	**1.26**	**1.51**	**2.71**	**18.7**
NO_X (lbs/MMBtu, from Duct Burners)	**na**	**0.038**	**0.026**	**0.026**	**0.033**	**0.1**
CO (lbs/hr, at HRSG Stack)	**14.5**	**23.1**	**26.3**	**25.3**	**24.1**	
CO (lbs/hr, from Duct Burner)	**na**	**1.57**	**4.75**	**4.32**	**3.18**	**28.1**
CO (lbs/MMBtu, from Duct Burners)	**na**	**0.057**	**0.098**	**0.074**	**0.039**	**0.15**

Table 3
100% Load Emissions Summary

Plant	Florida Power, Univ. FL Cogen. Facility
Location	Gainesville, Florida
Technicians	JTL, LRF, DTA
Source	GE Model LM-6000PC-Esprint Turbine

Test Run Number		1	2	3
Date		04/29/03	04/29/03	04/29/03
Start Time		11:52	13:10	14:28
End Time		12:58	14:16	15:35
Operational Data	**CoGen Name**			
Generator Output (MW)	GEN OUTPUT	49	48	49
Mean Turbine Exhaust Plenum Temperature (°F)	GT EXH AVG	864	864	864
Steam Injection (Klbs/hr)	GT NOX STM	34.58	34.57	34.52
Steam/Fuel Ratio (lb/lb)	STM/FUEL	1.797	1.805	1.793
Compressor Inlet Temperature (°F) dry	AMB TEMP AV	83.6	85.0	87.0
Compressor Inlet Temperature (°F) wet, predicted	INLET T2	67.7	68.5	68.7
Compressor Inlet Pressure (psia)	INLET P2	14.50	14.50	14.50
Post Cooler Humidity (%RH)	GT HUMID	101.0	101.0	101.0
Compressor Discharge Pressure (psig) Observed	GT P3	436.0	435.3	436.3
Fuel Data				
Turbine NG Fuel Flow (Klbs/hr)	GT FUEL FLW KPPH	19.20	19.16	19.21
Turbine Fuel Flow (SCF/hr)	GT FUEL FLW KSCFH	427900	426825	427967
Duct Burner Fuel Flow	DB Fuel Flow KSCFH	25.31	25.52	25.60
Fuel Lower Heating Value (Btu/SCF)		947	947	947
Published M-19 O2 F-Factor (DSCF/MBtu)		8710	8710	8710
Published M-19 CO2 F-Factor (DSCF/MBtu)		1040	1040	1040
Turbine Heat Input (MBtu/hr)		405.2	404.2	405.3
Duct Burner Heat Input (Mbtu/hr)		26.7	27.0	27.0
Total Heat Input		431.9	431.2	432.3
Total Sulfur (Gr/Ccf)		0.071	0.071	0.071
Total Sulfur in Fuel (wt %)		0.00023	0.00023	0.00023
% of Heat Input Curve		107.2	106.9	107.2
Ambient Conditions				
Barometer (in. Hg)		30.01	30.00	30.00
Temperature (°F dry)		80	84	86
Temperature (°F wet)		71	71	72
Humidity (lbs/lb of dry air)		0.01382	0.01288	0.01320
Environmental Services Measurements				
NOx (ppmvd)		19.01	20.56	20.76
CO (ppmvd)		19.29	21.92	20.98
O2 (%)		14.58	14.37	14.31
CO2 (%)		3.44	3.82	3.82
Environmental Services Calculated Values				
Fo		1.837	1.709	1.725
Stack Flow via O2 F-Factor (DSCFH)		11671848	11268110	11195392
Stack Flow via CO2 F-Factor (DSCFH)		12250877	11004487	11033930
NOx (ppmvd @ 15% O2)		17.7	18.6	18.6
NOx (lbs/hr) per O2 F-factor		26.5	27.7	27.8
CO (ppmvd @ 15% O2)		18.0	19.8	18.8
CO (lbs/hr) per O2 F-factor		16.4	18.0	17.1
SO2 (vol % @ 15% O2)		4.17E-06	4.17E-06	4.17E-06
SO2 (lbs/hr)		0.0867	0.0865	0.0867

5/8/2003

Florida Power Corporation

Prepared by J. T. Long

Department of Environmental Protection

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit:

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **Progress Energy Florida, Inc**	
2. Site Name: **University of Florida Cogen**	
3. Facility Identification Number: **0010001**	
4. Facility Location... Street Address or Other Locator: **Mowery Rd at University of Florida** City: **Gainesville** County: **Alachua** Zip Code: **32611**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **Chris Bradley, Senior Environmental Specialist**
2. Application Contact Mailing Address... Organization/Firm: **Progress Energy Florida** Street Address: **299 1st Avenue, N., PEF 903** City: **St. Petersburg** State: **FL** Zip Code: **33701**
3. Application Contact Telephone Numbers... Telephone: **(727) 820 - 5962** ext. Fax: **(727) 820 - 5229**
4. Application Contact E-mail Address: **chris.bradley@pgnmail.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 9/13/10	3. PSD Number (if applicable):
2. Project Number(s): 0010001-011-AC	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is being submitted to obtain: (Check one)

Air Construction Permit

☐ Air construction permit.

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).

☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

☐ Initial Title V air operation permit.

☐ Title V air operation permit revision.

☐ Title V air operation permit renewal.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.

☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

☒ Air construction permit and Title V permit revision, incorporating the proposed project.

☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

☒ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

This application from Florida Power Corporation, d/b/a Progress Energy Florida, Inc (PEF) is to request concurrent processing of revisions to the Title V (TV) and air construction (AC) permits. Specifically, PEF is seeking revisions to the combustion turbine (CT) emission limits for CO (TPY, lb/hr and ppmvd) and NOx (TPY), as well as the compliance testing requirements for the duct burner (DB).

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
005	Duct Burner System with HRSG		
007	Combustion Turbine		

Application Processing Fee

Check one: ☐ Attached - Amount: $_____ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1. Owner/Authorized Representative Name :

2. Owner/Authorized Representative Mailing Address...
   Organization/Firm:
   Street Address:
   City: State: Zip Code:

3. Owner/Authorized Representative Telephone Numbers...
   Telephone: ( ) - ext. Fax: ( ) -

4. Owner/Authorized Representative E-mail Address:

5. Owner/Authorized Representative Statement:

   I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.

   Signature

   9/10/2010
   Date

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name: **Wilson Hicks, Plant Manager**

2. Application Responsible Official Qualification (Check one or more of the following options, as applicable):

   [X] For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C.

   [ ] For a partnership or sole proprietorship, a general partner or the proprietor, respectively.

   [ ] For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official.

   [ ] The designated representative at an Acid Rain source or CAIR source.

3. Application Responsible Official Mailing Address...
   Organization/Firm: **Progress Energy Florida, Inc.**
   Street Address: **University of Florida Cogeneration Plant, Mowry Rd, Bldg. 82**
   City: **Gainesville** State: **FL** Zip Code: **32611-2295**

4. Application Responsible Official Telephone Numbers...
   Telephone: **(352) 337 - 6904** Fax: ( ) -

5. Application Responsible Official E-mail Address: **wilson.hicks@pgnmail.com**

6. Application Responsible Official Certification:

   I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application.

Wilson Hicks — Signature

9/10/2010 — Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Scott Osbourn, Associate and Senior Consultant**
   Registration Number: **57557****
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates**
   Street Address: **5100 West Lemon Street, Suite 208**
   City: **Tampa** State: **FL** Zip Code: **33609**
3. Professional Engineer Telephone Numbers...
   Telephone: **(813) 287 - 1717** ext. **53304** Fax: **(813) 287 - 1716**
4. Professional Engineer E-mail Address: **sosbourn@golder.com**
5. Professional Engineer Statement:

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

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

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

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

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

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

Signature

Date 9/10/10

(seal)

SCOTT OSBOURN LICENSE NO. 57557 STATE OF FLORIDA PROFESSIONAL ENGINEER

* Attach any exception to certification statement.
** Board of Professional Engineers Certificate of Authorization # 00001670

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone **17** East (km) **369.39** North (km) **3279.29**		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) **29° 38' 18" N** Longitude (DD/MM/SS) **82° 21' 46" W**	
3. Governmental Facility Code: **0**	4. Facility Status Code: **Active**	5. Facility Major Group SIC Code: **49**	6. Facility SIC(s): **4911**
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: **Wilson B Hicks Jr., Plant Manager**
2. Facility Contact Mailing Address... Organization/Firm: **FPC dba Progress Energy Florida, Inc.** Street Address: **Mowry Road, Bldg. 82** City: **Gainesville** State: **FL** Zip Code: **32611**
3. Facility Contact Telephone Numbers: Telephone: **(352) 337 - 6904** ext. Fax: **(352) 337 - 6920**
4. Facility Contact E-mail Address: **wilson.hicks@pgnmail.com**

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official E-mail Address:

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☐ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☐ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☐ One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
NOx	**A**	**Y**
CO	**A**	**N**
PM10	**A**	**N**
PM	**A**	**N**
SO2	**A**	**N**
VOC	**A**	**N**

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility-Wide Cap [Y or N]? (all units)	3. Emissions Unit ID's Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap
NOx	**Y**			**174.6**	**PSD Avoid**

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1. Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID:_____ [X] Previously Submitted, Date:_____
2. Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID:_____ [X] Previously Submitted, Date:_____
3. Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought)
   ☐ Attached, Document ID:_____ [X] Previously Submitted, Date:_____

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location:
   ☐ Attached, Document ID:_____ [X] Not Applicable (existing permitted facility)
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL):
   ☐ Attached, Document ID: NA
3. Rule Applicability Analysis:
   ☐ Attached, Document ID: NA
4. List of Exempt Emissions Units:
   ☐ Attached, Document ID:_____ [X] Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification:
   ☐ Attached, Document ID:_____ [X] Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.):
   ☐ Attached, Document ID:_____ [X] Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.):
   ☐ Attached, Document ID:_____ [X] Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.):
   ☐ Attached, Document ID:_____ [X] Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.):
   ☐ Attached, Document ID:_____ [X] Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.):
    ☐ Attached, Document ID:_____ [X] Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications

1. List of Exempt Emissions Units:
   ☐ Attached, Document ID:_____ ☒ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications

1. List of Insignificant Activities: (Required for initial/renewal applications only)
   ☐ Attached, Document ID:_____ ☒ Not Applicable (revision application)

2. Identification of Applicable Requirements: (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought)
   ☐ Attached, Document ID:_____
   ☒ Not Applicable (revision application with no change in applicable requirements)

3. Compliance Report and Plan: (Required for all initial/revision/renewal applications)
   ☐ Attached, Document ID:_____
   Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.

4. List of Equipment/Activities Regulated under Title VI: (If applicable, required for initial/renewal applications only)
   ☐ Attached, Document ID:_____
   ☐ Equipment/Activities Onsite but Not Required to be Individually Listed
   ☒ Not Applicable

5. Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only)
   ☐ Attached, Document ID:_____ ☒ Not Applicable

6. Requested Changes to Current Title V Air Operation Permit:
   ☒ Attached, Document ID: **Attachment 4** ☐ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1. Acid Rain Program Forms:

   Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):
   ☐ Attached, Document ID:_____ ☒ Previously Submitted, Date:_____
   ☐ Not Applicable (not an Acid Rain source)

   Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):
   ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____
   ☒ Not Applicable

   New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):
   ☐ Attached, Document ID:_____ ☐ Previously Submitted, Date:_____
   ☒ Not Applicable

2. CAIR Part (DEP Form No. 62-210.900(1)(b)):
   ☐ Attached, Document ID:_____ ☒ Previously Submitted, Date:_____
   ☐ Not Applicable (not a CAIR source)

Additional Requirements Comment

ATTACHMENT 4

UNIVERSITY OF FLORIDA
CO-GENERATION FACILITY
PERMIT NO: 0010001-009-AV

REQUESTED CHANGES
TO
TITLE V PERMIT CONDITIONS

University of Florida Co-Generation Facility
Requested Changes to Permit Conditions

Please find below the requested changes to the Title V Air Operation Permit No. 0010001-009-AV for the Florida Power Corporation d/b/a Progress Energy Florida, Inc. ("PEF") University of Florida Co-Generation Facility. Any requested changes are shown in red with strikethrough for deletion and underline for insertion.

1. *Section II, Facility-Wide Conditions, Specific Condition FW11 - PSD Applicability:* The requested change is to eliminate a portion of this condition that is no longer applicable to the facility. Therefore, the requested change is as follows:

   FW11. ~~PSD Applicability. Pursuant to PSD-FL-181, the permittee requested and received a 39.7 TPY net increase in NOX emissions, along with a combined total CT and DB NOX limitation of 174.6 TPY, in order to escape PSD New Source Review. Therefore, any net increase in NOX emissions of 0.3 TPY above the allowable limitation established in Facility-wide Condition **FW10** will initiate preconstruction review requirements pursuant to Rule 62-212.400, F.A.C., for NOX for the CT and DB as if construction of these emissions units had not yet begun. See Facility-wide Condition **FW10**.~~ As provided for in the permitting action of PSD-FL-181, issued August 17, 1992, the permittee elected not to provide appropriate spacing for future installation of NOX controls during the initial construction. If the permittee later applies for a permit modification to increase capacity, the retrofit costs associated with not making provisions for such technology (initially) shall not be considered in the retrofit analysis required for the future expansion. [Rule 62-212.400(12), F.A.C.; and, Permit Nos. AC01-204652/PSD-FL-181/PSD-FL-181A and 0010001-003-AC]

2. *Section III, Subsection A, Specific Condition A.19 – Sulfur Dioxide – Sulfur Content:* The requested change is an effort to provide flexibility for the analysis of sulfur in the fuels combusted in the emergency back-up boilers (EU Nos. 002 and 003) at the facility. Therefore, the requested change is as follows:

   A.19. Sulfur Dioxide - Sulfur Content. The permittee shall demonstrate compliance with the liquid fuel sulfur limit by the vendor providing a fuel analysis upon each fuel delivery <u>or by using a contracted laboratory and an approved ASTM method</u>. The fuel sulfur content percent by weight, for liquid fuels shall be evaluated using either: ASTM D2622-92, ASTM D2494-90, both D4057-88 and ASTM D129-91, ASTM D1552 or equivalent method, or the latest edition(s). Current applicable alternative methods that are approved ASTM methods as adopted in Rule 62-297.440(1), F.A.C. are also acceptable. [Rules 62-213.440, F.A.C., 62-296.406(3), F.A.C., 62-297.440, F.A.C., BACT; AC01-204652/PSD-FL-181]

   {Permitting Note: The permittee may elect to <u>use the vendor provided fuel analysis upon each fuel delivery or perform</u> on-site sampling analysis using the ASTM

*methods listed above and in accordance with Part 75 Appendix D (See Specific Condition **B.29.**) instead of relying upon the vendor's delivery receipts.}*

3. *Section III, Subsection B, Specific Condition B.7 – CT Emission Limit Summary:* The requested changes are an effort to create a table that is easier to read and understand and to eliminate a footnote that is no longer applicable to this emission unit. Therefore, the requested changes are as follows:

B.7. CT Emissions Limit Summary. Pollutant and visible emissions from the CT shall not exceed the following allowable limits:

Pollutant	Fuel Type	Basis of Limit	CT Allowable Limits	
		@ 15% O2	lbs/hr	TPY
NO_X	NG	25 ppmvd [5] / 25.0 ppmvd [3, 5, 6]	39.63	141 [1, 2]
	No. 2 FO	42.0 ppmvd [5, 6]	66.33	141 [1, 2]

Pollutant	Fuel Type	CT Allowable Limits		
		@ 15% O2	lbs/hr	TPY
SO_2	No. 2 FO	0.015%, by volume[7]	(BACT) 0.5% Sulfur content, by weight	
CO	NG	31.6 ppmvd	29.98	127.58
	No. 2 FO	75.0 ppmvd	70.59	7.79
	NG and No. 2 FO			135.2 (total)

Parameter	Fuel Type	CT Allowable Limit
VE	NG	10% opacity [4]
VE	No. 2 FO	20% opacity [4]

[1] The NOX allowable limit was accepted by the applicant to escape PSD New Source Review. This limit includes the total annual NOX emissions from the firing of all fuels.

~~[2] Any net increase in NOX emissions of 0.3 TPY above the combined allowable limits of the CT and DB (174.6 TPY; and, see Specific Conditions **B.8.** and **FW11.**) will initiate preconstruction review requirements pursuant to Rule 62-212.400(5), F.A.C., for NOX for the CT and DB as if construction of these emissions units had not yet begun.~~

[3] 30-day rolling average, compliance timeframe. See Specific Condition **B.21**.

[4] Since the CT and DB are in series, the opacity standard is applicable when the CT or the CT and DB are in operation, except when the CT is firing No. 2 FO, at which time the CT's opacity standard for FO will be in effect. See Specific Condition **B.8**.

[5] Basis of allowable limit - performance testing using EPA Method 7E or EPA Method 20.

[6] Compliance is demonstrated using a NOX CEMS. See Specific Condition **B.20**.

[7] In lieu of an annual compliance test for SO2, the fuels fired in the combustion turbine and/or duct burner shall have the following sulfur limits: (See Specific Conditions **B.13.** and **B.29.**) NG: 1.0 grain sulfur per 100 standard cubic feet. No. 2 FO: 0.5 percent, by weight, sulfur [PSD-FL-181: BACT]; and, 0.8 percent, by weight, sulfur [40 CFR 60.333, Subpart GG].

[8] Based on 100% load of NG at 59 °F inlet conditions; and, 8,541 hrs/yr operation.

[9] Based on 100% load of No. 2 FO at 59 °F inlet conditions; and, 219 hrs/yr operation.

4. *Section III, Subsection B, Specific Condition B.8 – DB Emission Limit Summary:* The requested changes are an effort to incorporate a stack test method for determining CO emission from the duct burner and to eliminate a footnote that is no longer applicable to this emission unit. Therefore, the requested changes are as follows:

B.8. DB Emissions Limit Summary. Pollutant and visible emissions from the DB shall not exceed the following allowable limits:

			DB Allowable Limits	
Pollutant	**Fuel Type**	**Basis of Limit**	**lbs/hr**	**TPY**
NOx [1]	Natural Gas	0.1 lb/mmBtu[5, 6]	18.7 [3]	24.6 [1, ~~2~~]
CO	Natural Gas	0.15 lb/mmBtu [5]	28.1	36.9
Parameter	**Fuel Type**	**DB Allowable Limit**		
VE	Natural Gas	10% opacity [4]		

[1] The NOX allowable limit was accepted by the applicant to escape PSD New Source Review.

~~[2] Any net increase in NOX emissions of 0.3 TPY above the combined allowable limits of the CT and DB (174.6 TPY; and, see Specific Conditions **B.7.** and **FW11.**) will initiate preconstruction review requirements pursuant to Rule 62-212.400(5), F.A.C., for NOX for the CT and DB as if construction of these emissions units had not yet begun.~~

[3] 30-day rolling average, compliance timeframe. (See Specific Condition **B.21.**)
[4] Since the CT and DB are in series, the opacity standard is applicable when the CT or the CT and DB are in operation, except when the CT is firing No. 2 distillate fuel oil, at which time the CT's opacity standard for fuel oil will be in effect. See Specific Condition **B.7.**
[5] Basis of allowable limit - performance testing using EPA Method 10 and 7E or EPA Method 20.

5. *Section III, Subsection B, Specific Condition B.13 – Sulfur Dioxide:* The requested change is an effort to specifically define the relationship between permitted emissions of sulfur dioxide (SO2) and sulfur (S) delineated in Specific Condition **B.13**. Therefore, the requested change is as follows:

> **B.13.** Sulfur Dioxide.
> a. *Combustion Turbine.*
> (1) ~~When firing natural gas, SO_2 emissions shall not exceed 0.015 percent by volume at 15% O_2 and on a dry basis. The sulfur content of the natural gas shall not exceed 1.0 grain per 100 standard cubic feet of natural gas.~~ The sulfur content of the natural gas shall not exceed 1.0 grain per 100 standard cubic feet of natural gas, which will ensure the SO_2 emissions shall not exceed 0.015 percent by volume at 15% O_2 and on a dry basis when firing natural gas.

Furthermore, Specific Condition **B.13** states the sulfur content of the natural gas shall not exceed 1.0 grain per 100 standard cubic feet of natural gas. However, PEF's contract with Florida Gas Transmission (FGT) only requires less than 20 grains of sulfur. If the gas supplied by the vendor exceeds 1.0 grain, PEF requests that a series of actions be included to ensure the sampling and analysis are not an error or anomaly. PEF requests language regarding gas testing be included that mirrors that of 40 CFR Part 75 Appendix D 2.3.1.4(b), which states -

> "If the results of the fuel sampling under paragraph (a)(2) or (a)(3) of this section show that the fuel does not meet the definition of pipeline natural gas in §72.2 of this chapter, but those results are believed to be anomalous, the owner or operator may document the reasons for believing this in the monitoring plan for the unit, and may immediately perform additional sampling. In such cases, a minimum of three additional samples must be obtained and analyzed, and the results of each sample analysis must meet the definition of pipeline natural gas."

6. *Section III, Subsection B, Specific Condition B.14 – Excess Emissions Allowed:* Although Specific Condition B.14 is template language and has for a basis 62-210.700(1), F.A.C. there appears to be a contradiction in this permit condition with the NOx emission limit averaging period. According to Specific Condition B.7, there is not a violation of the NOx emission standard until the 30-day rolling average limit is exceeded. The question then becomes – What "two hours in any 24-hour period" is being referred to in this permit condition? In addition, this permit condition is presumably referring to a rolling 24-hour compliance period

(i.e. ...in no case exceed two hours in ANY 24 hour period.); however, Specific Condition B.21 refers to a 24-hour block average (i.e., midnight to midnight.). Furthermore, if this condition is retained, PEF requests the accommodation of multiple start-ups/shutdowns in any 24-hour period.

B.14. Excess Emissions Allowed. Excess emissions resulting from startup, shutdown or malfunction shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case *exceed two hours in any 24 hour period* unless specifically authorized by the Department for longer duration.

7. *Section III, Subsection B, Specific Condition B.18 – Fuel Consumption Rates Monthly Monitoring:* The requested change is an effort to allow for some additional flexibility when determining monthly fuel consumption and hours of operations. Therefore, the requested change is as follows:

B.18. Fuel Consumption Rates Monthly Monitoring. By the ~~fifth~~ fifteenth calendar day of each month, the permittee shall record the monthly fuel consumption and hours of operation for the CT. The information shall be recorded in a verifiable manner and shall summarize the previous month of operation and the previous 12 months of operation. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department.

8. *Section III, Subsection B, Specific Condition B.21- Use of NOX CEMS for CT and Duct Burner Compliance:* The requested change is to part b. of this permit condition and is an effort to remain consistent with the 30-day rolling average for NOx emissions. Therefore, the requested change is as follows:

B.21.b. The daily ~~rolling~~ average utilized to determine the 30-day rolling average compliance value shall be calculated based on the proportion of hours operated in a day (midnight to midnight) that the CT or both the CT and DB are operating. Any portion of an hour that the DB operates shall be recognized as an hour-period on the daily operation. For example, in a given daily timeframe, with 20 hours of CT operation only while firing natural gas and 4 hours of CT/DB operation while firing natural gas:

9. *Section III, Subsection B, Specific Condition B.25- Compliance Tests Prior Renewal* The requested change is to clearly link the monitoring/testing of fuel for sulfur content as an acceptable alternative to conducting SO_2 compliance testing. Therefore, the requested change is as follows:

University of Florida Co-Generation Facility
Requested Changes to Permit Conditions

B.25. Compliance Tests Prior to Renewal. Compliance tests shall be performed for **NOX, CO, VE** and **SO2** once every 5 years. The tests shall occur prior to obtaining a renewed operating permit to demonstrate compliance with the emission limits in Specific Conditions **B.7. – B.13.** Also see Specific Condition **B.29.**

10. *Section III, Subsection B, Specific Condition B.27- Compliance Tests Prior Renewal* The requested change is to clearly define the method of determining annual carbon monoxide (CO) mass emissions. Therefore, the requested change is as follows:

    B.27. Carbon Monoxide. EPA Method 10 shall be used to demonstrate compliance with the CO limits of this permit, in accordance with Chapter 62-297, F.A.C., and 40 CFR 60, Appendix A. For purposes of demonstrating compliance with the annual limit of tons per year, hourly heat input rates (MMBtu/hr) shall be used to convert lbs/MMBtu of CO to lbs/hr of CO and actual operating hours shall be used to obtain tons per year.

11. *Section III, Subsection B, Specific Condition B.29 - Compliance Tests Prior Renewal* The requested change is to provide for additional flexibility in determining fuel sulfur analysis. Therefore, the requested change is as follows:

    B.29. Sulfur Dioxide Annual Test Waiver. In lieu of an annual compliance test for SO2, the fuels fired in the CT and the DB shall meet the sulfur content limits listed in Specific Condition **B.13.** Ongoing compliance with the fuel sulfur limit for natural gas and fuel oil shall be demonstrated by the fuel supplier's analysis reports containing the sulfur content of the fuel being supplied. Methods for determining the sulfur content of natural gas shall be ASTM methods D4084-82, D3246-81, D5504* or more recent versions or equivalent approved ASTM analytical methods. Current applicable alternative methods that are approved ASTM methods as adopted in Rule 62-297.440(1), F.A.C. are also acceptable. Ongoing compliance with the fuel oil sulfur limits shall be demonstrated by fuel analyses certified according to the provisions of 40 CFR 75, Appendix D, by the fuel supplier or by a contracted laboratory using an approved method. At the request of the Department's Northeast District office, the permittee shall perform additional sampling and analysis for the fuel sulfur content. [Rules 62-4.070(3) & 62-4.160(15), F.A.C.; *Applicant Request; and, Permit No. 0010001-003-AC]

    {Permitting Note: The permittee may elect to perform on-site sampling and analysis using the ASTM methods listed above instead of relying upon the vendor's delivery receipts.}

12. *Section III, Subsection B, Specific Condition B.31 – Re[porting Schedule:* The requested change is to avoid immediate notification/reporting of excess emission associated with start-

up and shutdown, PEF requests the removal of reporting excess emissions due to start-up and shutdown from immediately from Specific Conditions **B.31** and **B.35**; excess emission due to malfunction will be reported immediately. Therefore, the requested change is as follows:

B.31. Reporting Schedule. The following reports and notifications shall be submitted to the Compliance
Authority:

Report	Reporting Deadline	Related Condition(s)
Notice of Excess Emissions	Semi-annually	B.34.
Notice of Excess Emissions from~~, Startup, Shutdown and~~ Malfunction	Immediately	B.35.

B.35. Notification of Excess Emissions During ~~Startup, Shutdown, and~~ Documented Unavoidable Malfunctions.

If a CEM system reports emissions in excess of the standard, the permittee shall notify the Department's Northeast District office within (1) working day with a preliminary report of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. [Rule 62-210.700, F.A.C. and Permit No. 0010001-003-AC]

13. PEF would like to add a permit condition that provides for the change out of the combustion turbine engine with a like/kind replacement as part of the routine maintenance schedule of the unit. For further support of this request, attached is an "Explanation of Combustion Turbine Routine Maintenance Schedule".

University of Florida Co-Generation Facility
Explanation of Combustion Turbine Routine Maintenance Schedule

The following is a brief description of recommended maintenance intervals for the General Electric (GE) manufactured LM6000 combustion turbine. At each inspection and major maintenance interval, all GE-required maintenance requirements are followed and any GE Technical Bulletins that require action are implemented as part of next scheduled inspection or maintenance interval.

The GE maintenance intervals and brief description are as follows:

1. **4,000-Hour Maintenance**

   At each Spring and Fall outage, Progress Energy Florida, Inc. (PEF) performs normal routine/preventative maintenance (PM) on the engine, enclosure for the engine and generator that includes piping, engine supports, instrumentation, cooling fans, pumps, hydraulic starting equipment, ductwork, auxiliary systems, etc. This maintenance includes an overall inspection, boroscope and appropriate maintenance of the engine.

2. **25,000-Hour Maintenance**

   The GE LM6000 engine requires significant routine maintenance every 25,000 hours of operation. An element of the required 25K-hour maintenance is a "hot section" exchange. The "hot section" exchanges include a like-kind replacement of the combustor, high-speed turbine including blades, nozzles and other components. The replacements are either new or refurbished like-kind parts to restore the components to the Original Equipment Manufacturer (OEM) specifications.

3. **50,000-Hour Maintenance**

   At this maintenance interval a major overhaul of the unit is conducted and, in addition to the following, includes the 25,000-hour interval maintenance items. In addition to the "hot section" exchange, it also includes inspecting every engine component, refurbishing and returning the component to original like-kind OEM specifications. This includes the high and low-speed compressors and turbines.

At each inspection and major maintenance, all required GE maintenance requirements are followed. Any GE technical bulletin that requires action is implemented as part of any inspection or maintenance interval. The replacements are either new or refurbished to bring the components back to Original Equipment Manufacturer (OEM) specifications.