Feb. 8, 2000 GRU e-mail

PERMITTEE:

Gainesville Regional Utilities (GRU)
Post Office Box 147117 (A134)
Gainesville, Florida 32601-7060

Permit No.	PSD-FL-276
File No.	0010005-002-AC
SIC No.	4911
Expires:	December 31, 2001

Authorized Representative:

Michael L. Kurtz – General Manager

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: a nominal 83 megawatt (MW) natural gas and No. 2 distillate fuel oil-fired combustion turbine-electrical generator; an unfired heat recovery steam generator (HRSG); a 102 foot stack for combined cycle operation; a 88 foot bypass stack for simple cycle operation and ancillary equipment. Steam produced by the HRSG will be routed to the existing Unit No. 8 steam turbine-electrical generator to generate 40-50 MW of additional electricity. The combustion turbine may be equipped with inlet air conditioning devices (e.g., evaporative chillers, foggers, etc.). This unit is designated as Combined Cycle Unit CC-1 and will be located at the J.R. Kelly Generating Station, 605 Southeast 3rd Street in Gainesville, Alachua County. UTM coordinates are: Zone 17; 372.0 km E; 3,280.2 km N.

STATEMENT OF BASIS:

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

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

This existing GRU J.R. Kelly Generating Station consists of: three natural gas and distillate fuel oil-fired nominal 16 MW simple cycle combustion turbine-electrical generators designated as Combustion Turbine Nos. 1, 2, and 3; two natural gas and No. 6 fuel oil-fired conventional boilers designated as Units 7 and 8; one natural gas-fired conventional boiler designated as Unit 6 (in cold standby); a recirculating cooling tower system, including two fresh-water mechanical draft cooling towers; fuel oil storage tanks; water treatment facilities, and ancilliary support equipment. The steam turbine-electrical generators associated with Units 6, 7 and 8 have nameplate ratings of 19, 25 and 50 MW respectively.

Unit No. 8 boiler will cease operation following completion of construction of Combined Cycle Unit CC-1.

NEW EMISSION UNIT

This permit addresses the following emission unit:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
009	Power Generation	Unit CC-1. One dual fuel nominal 133 Megawatt Combined Cycle Combustion Turbine-Electrical Generator with unfired HRSG.

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of Air Pollution as defined in Rule 62-210.200. It is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. and is a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

PSD review and a Best Available Control Technology (BACT) determination were required and performed for this project for emissions of carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}). The new Combined Cycle Unit CC-1 is subject to the New Source Performance Standard for Stationary Gas Turbines at 40CFR60, Subpart GG.

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

This project is not subject to the requirements of Chapter 403, Part II, F.S., Electrical Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility will not change.

RELEVANT DOCUMENTS:

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

- Application received September 7, 1999
- Department letter to GRU dated October 6, 1999
- Comments from the Fish and Wildlife Service dated October 6, 1999
- GRU letters dated October 25, November 10, December 2, and December 16, 1999
- Public Notice Package including Technical Evaluation and Preliminary Determination dated December 17, 1999
- Letters from EPA Region IV dated November 10 and January 21, 2000

- Department's Final Determination and BACT determination issued with this Final Permit.

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION II - ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Northeast District Office 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256-7590 and phone number 904/448-4300 and Northeast District Branch Office, 101 NW 75 Street, Suite 3 Gainesville, Florida 32607 and phone number 352/333-2850.
2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]
3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.
4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]
5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility as defined in Rule 62-210.200 F.A.C.. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]
6. Construction Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [Rules 62-4.210(2)(3), 62-210.300(1)(a), 62-4.070(3), F.A.C and 40 CFR 52.21(r)(2)]
7. BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction, or extension of the December 31, 2001 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [Rule 62-4.070(3) F.A.C., 40 CFR 52.21(j)(4)]

Comment: GRU still believes that there is no regulatory basis for a BACT re-evaluation upon extension of the expiration date of the construction permit.

8. Permit Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation 30 days prior to the expiration of the permit, if possible (Rule 62-4.080, F.A.C.)..
9. Application for Title IV Permit: An application for a Title IV Acid Rain Permit, must be submitted to the U.S. Environmental Protection Agency Region IV office in Atlanta, Georgia and a copy to the DEP's Bureau of Air Regulation in Tallahassee 24 months before the date on which the new unit begins serving an electrical generator (greater than 25 MW). [40 CFR 72]

SECTION II - ADMINISTRATIVE REQUIREMENTS

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

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

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

13. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. The permittee shall design this unit to accommodate adequate testing and sampling locations for compliance with the applicable emission limits listed in Specific Conditions No. 15 through 17. [Rule 62-4.070(3), Rule 62-297.310 (6) F.A.C.]

14. Semi-annual Reports: Except as otherwise specified herein (See Specific Condition 39), semi-annual excess emission reports, in accordance with 40 CFR 60.7 (a)(7)(c) (1999 version), shall be submitted to the DEP's Northeast District and Northeast District Branch Offices. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334~~, except as otherwise specified herein (See Specific Condition 39)~~. Excess emission reports may be submitted on a quarterly basis at the permittee's discretion.

Comment: Specific Condition 39 provides an exception to semi-annual reporting and not to the information required in the report.

APPLICABLE STANDARDS AND REGULATIONS:

1. NSPS Requirements – Subpart GG: The Unit shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies when determining compliance with the emissions limitations specified therein.

2. NSPS Requirements – Subpart A: These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

   40CFR60.7, Notification and Recordkeeping
   40CFR60.8, Performance Tests
   40CFR60.11, Compliance with Standards and Maintenance Requirements
   40CFR60.12, Circumvention
   40CFR60.13, Monitoring Requirements
   40CFR60.19, General Notification and Reporting requirements

3. BACT Requirements: This emissions unit is subject to Best Available Control Technology (BACT) emissions limits for carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}).

4. Applicable Regulations: Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations (CFR) Title 40, Parts 51, 52, 60, 72, 73, and 75, adopted by reference in Rule 62-204.800, F.A.C. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

GENERAL OPERATION REQUIREMENTS

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

6. Combustion Turbine Capacity: The maximum heat input rates, based on the higher heating value (HHV) of each fuel to this Unit at ambient conditions of 20°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,083 million Btu per hour (mmBtu/hr) when firing natural gas, nor 1,121 mmBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

   {Permitting note: The heat input rates have been placed in the permit to identify the capacity of the emission unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emission's unit rate capacity (or to limit future operation to 105 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. The owner or operator is expected to determine heat input whenever emission testing is required in order to demonstrate what percentage of the rated capacity that the unit was tested. Such heat input determinations may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heating value of the fuel determined by the fuel vendor or the owner or operator.}

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

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

9. Operating Procedures: Operating procedures shall include good operating practices in accordance with the guidelines and procedures as established by the equipment manufacturers to control emissions. [Rule 62-4.070(3), F.A.C.]

10. Hours of Operation: Combined Cycle Unit 1 may operate 8760 hours per year of which no more than 1000 hours per year may be on distillate fuel oil (0.05% S content). The unit may not operate in excess of the annual nitrogen oxides (NO_X) emission cap described in Specific Condition 15 below. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

CONTROL TECHNOLOGY

11. DLN Combustion Technology: The permittee shall install, tune, operate and maintain Dry Low NO_X combustors on this combustion turbine. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific DLN system prior to commencement of operation. [Rule 62-4.070 F.A.C.]

12. Water Injection: The permittee shall install, calibrate, maintain and operate an automated water injection system for the unit for use when firing fuel oil. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system prior to commencement of operation. [Rule 62-4.070 F.A.C.]

13. Combustion Controls: The permittee shall employ "good operating practices" in accordance with the manufacturer's recommended operating procedures to control CO, and NO_X, and VOC emissions. Prior to the required initial emissions performance testing, the combustion turbine, the DLN-1 combustors, and the control system shall be tuned to comply with the CO, and NO_X, and VOC emission limits. Thereafter, these systems shall be maintained and tuned, as necessary, in accordance with manufacturer's recommendations for emissions control and to comply with the permitted emission limits. [Design, Rules 62-4.070 (3) and 62-212.400, F.A.C.].

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

EMISSION LIMITS AND STANDARDS

The following emission limits and standards shall apply upon completion of the initial compliance tests, performance tests and certification tests, as applicable and per pollutant.

15. Nitrogen Oxides (NO_X) Emissions:

- Natural Gas Operation. **The concentration of NO_X in the stack exhaust gas shall not exceed 9 ppmvd at 15% O_2 on a** 720 operating hour ~~30-day~~ **block average. Compliance will be demonstrated by the continuous emission monitor system (CEMS). Emissions of NO_X in the stack exhaust shall not exceed 32 pounds per hour (lb/hr at ISO conditions) to be demonstrated by initial stack test. [Rule 62-4.070(3) F.A.C.]**

Comment: GRU suggests that the block average be specified in terms of the equivalent number of hours in 30 days (i.e., 720) so that averages are calculated based on the same number of hours each time.

- Fuel Oil Operation. **The concentration of NO_X in the stack exhaust gas shall not exceed 42 ppmvd at 15% O_2 on a** 720 operating hour ~~3-hour~~ **block average. Compliance will be demonstrated by the CEMS. Emissions of NO_X shall not exceed 166 lb/hr (at ISO conditions) to be demonstrated by initial stack test. [Rule** ~~62-212.400~~, F.A.C.]

Comment:

- The Dept. has indicated it will accept a consistent averaging time between natural gas and fuel oil combustion.
- GRU suggests that the block average be specified in terms of the equivalent number of operating hours (i.e., 720 hours) in 30 days so that the averages are calculated based on the same number of hours each time.
- NOx was not subject to PSD review - the rule reference is not appropriate.
- Annual Emission Cap: **Total emissions of NO_X from Unit CC-1 shall not exceed 133 tons per calendar year in order to net out of PSD.** ~~Annual emissions shall be calculated using the methodology in 40 CFR 75 and shall be reported to the District office on the Annual Operating Report. The owner or operator shall immediately notify the Department if annual emissions exceed the NO_X cap based on cumulative calculations which are done each quarter.~~ **[Applicant Request to Avoid PSD requirements of Rule 62-212.400, F.A.C., Rule 62-4.070, F.A.C.]**

Comment: Language has been deleted to simplify and clarify the permit. This condition addresses emission limitations. The deleted language is redundant because it is already included in Specific Condition 26, which addresses methodology for calculating annual emissions and reporting requirements.

16. Carbon Monoxide (CO) Emissions:

- Natural Gas – First Year. **During only the first year of operation, the concentration of CO in the stack exhaust while operating on natural gas shall not exceed 25 ppmvd.** Emissions of CO shall not exceed **54 lb/hr** (at ISO conditions). **Compliance shall be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]**
- **Natural Gas (Second Year and Beyond) or Fuel Oil. The concentration of CO in the stack exhaust shall not exceed 20** ppmvd at 15% O_2 percent oxygen. Emissions of CO shall not exceed **43 lb/hr**

(at ISO conditions). Compliance shall be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

17. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC (methane equivalent) in the stack exhaust gas while burning natural gas (fuel oil) shall not exceed 1.4 (3.5) ppmvw. Emissions of VOC while burning natural gas (fuel oil) shall not exceed 1.8 (4.5) lb/hr (at ISO conditions) to be demonstrated by initial-stack test using EPA Method 18, 25 or 25A. [Rule ~~62-212.400~~, F.A.C.]

Comment: VOC's were not subject to PSD - the regulatory reference is not applicable.

18. **Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 20 grains per 100 standard cubic foot) or by firing No. 2 or superior grade distillate fuel oil with a maximum 0.05 percent sulfur for up to 1000 hours per year. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions 42 and 43 will demonstrate compliance with the applicable SO_2 NSPS [40CFR60 Subpart GG and Rules 62-4.070(3), and 62-204.800(7), F.A.C.]**

19. Particulate Matter (PM/PM_{10}) **PM/PM_{10} emissions shall not exceed 5 lb/hr when operating on natural gas and shall not exceed 10 lb/hr when operating on fuel oil. Visible emissions testing shall serve as a surrogate for** PM/PM_{10} **compliance testing. [Rule 62-212.400,** reference?, F.A.C.].

Comment: PM was not subject to PSD review - the appropriate regulatory reference should be provided if PM limits are to be included herein. GRU does not believe there is a regulatory basis for inclusion of PM.

20. **Visible emissions (VE): VE emissions shall serve as a surrogate for PM/PM_{10} emissions from the combustion turbine and shall not exceed 10 percent opacity from the stack in use. [Rules 62-4.070 (3), 62-212.400 F.A.C.]**

EXCESS EMISSIONS

21. Excess Emissions Allowed/Excluded from Short-term Limits: **Excess emissions resulting from startup, shutdown, fuel switching or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except as follows:**

- **During "cold start-up" to combined cycle plant operation up to four hours of excess emissions are allowed.**
- **During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed.**
- **Unless authorized by the Department.**

Excess NOx emissions are defined as one-hour periods when NOx emissions are above 9/42 ppmvd @ 15% oxygen while firing natural gas and fuel oil, respectively.

Cold start-up is defined as a startup that occurs after a complete shutdown lasting at least 48 hours.

NO_X CEM data shall be recorded and included in calculating the annual **NO_X emissions cap.**

[Applicant Request, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.].

Comment: Suggested language was added for clarification and for consistency with Specific Condition 25.

22. Excess Emissions Prohibited: **Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C.** These excess emissions shall be included in the 720 operating hour ~~30-day~~ **block** average ~~(gas) and the 3-hr block average (oil)~~ for NO_X.

COMPLIANCE DETERMINATION AND TESTING REQUIREMENTS

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

24. Annual, Initial and Performance Testing: **Initial (I) performance tests (for both fuels) shall be performed by the deadlines in Specific Condition 23.** Initial tests shall also be conducted after any substantial modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as change to a different type of combustors. **Year two (YR2) compliance testing for CO shall be performed in the second year of operation. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on this units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.**

- **EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A). Annual testing is applicable to fuel oil and only if fuel oil is used for more that 400 hours during the preceding 12-month period.**
- **EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" I and A** (YR2 and beyond, gas only)).
- **EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG. Test data shall be corrected to ISO conditions.**
- EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.

25. Continuous Compliance with the Short-term NO_X Emission Limits:

- Continuous compliance with the short-term NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 720 operating hours ~~30-day~~ **block** average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each 720 operating ~~day~~ hours and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the ~~previous 30 days~~ next 720 operating hours. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]
- ~~Compliance with the NO_X emission limits when firing oil shall be demonstrated with the CEM system based on a 3-hour block average basis. Based on CEMS data, a separate compliance~~

~~determination is conducted at the end of each 3-hour period and is calculated from the arithmetic average of all valid hourly emission rates during the previous 3-hour period. [Rules 62-4.070(3) F.A.C., 62-210.700, F.A.C., and 40 CFR 75]~~

Comment: The Dept. has indicated it will use the same averaging period for natural gas and fuel oil combustion.

- A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. Valid hourly emission rates shall not include periods of start up, shutdown, fuel switching, or malfunction unless not authorized by 62-210.700 F.A.C. or Specific Condition 21.
- Periods when the ~~30-day block average (gas), 3-hr block average (oil)~~ 720 operating hour block average or the 133 TPY calendar year cap NOx exceeds the emission limitations specified in Condition 15, shall be reported as required by Condition 39.

26. Compliance with the NO_X Annual Emission Cap:

Total emissions of NO_X from Unit CC-1 shall not exceed 133 tons per calendar year in order to net out of PSD. Annual emissions shall be calculated using the methodology in 40 CFR 75.72 and Appendix F, Section 8.4 **and shall be reported to the District office on the Annual Operating Report. The owner or operator shall** ~~immediately~~ **notify the Department** as specified in Specific Condition 39 **if annual emissions exceed the NO_X cap based on cumulative calculations which are done each quarter. [Applicant Request to Avoid PSD requirements of Rule 62-212.400, F.A.C., Rule 62-4.070, F.A.C.]**

Comment:

- In its comments dated January 21, 2000 GRU provided a specific methodology (excerpted from 40 CFR 75) for calculating NOx emissions. Since this was included to clarify the permit conditions for operating personnel, GRU suggests that the language be retained as specified in the referenced comments with the following revision:
  - For each calendar quarter or year, NOx mass emissions (in tons) will be calculated as follows:

    NOx (in tons) = (Sum of all hourly NOx mass emissions in lbs for the given time period)/2000

- Condition 39 provides a specific timeframe for reporting if the NOx cap is exceeded.

27. Compliance with the SO_2 and PM/PM_{10} emission limits: **Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1998 version).** [Applicant request]

28. Compliance with CO emission limit: **An initial test for CO, shall be conducted concurrently with the initial NO_X test, as required. The initial NO_X and CO test results shall be the average of three valid one-hour runs. Annual compliance testing for CO may be conducted at less than capacity when compliance**

testing is conducted concurrent with the RATA testing for the NO_X CEMS required pursuant to 40 CFR 75. Alternatively to annual testing in a given year, periodic tuning data may be provided to demonstrate compliance in the year the tuning is conducted. [Rule 62-297.310(7)(a) 4.; Rule 62-212.400 and 62-4.070(3) F.A.C.]

29. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO and VE limits and periodic tuning data will be employed as surrogates and no annual testing is required.[Rule 62-6.070(3) F.A.C]

30. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test until a new test is conducted.

    Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C. [Rule 62-297.310(2) F.A.C.]

31. Test Notification: The DEP's Northeast District and Northeast District Branch Offices shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s). [Rule 62-297.310(7)(a)9 F.A.C and 40 CFR 60.7 and 60.8]

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

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

NOTIFICATION, REPORTING, AND RECORDKEEPING

34. Records: All measurements, records, and other data required to be maintained by GRU shall be recorded in a permanent form and retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These records shall be made available to DEP representatives upon request. [Rules 62-4.160(14) and 62-213.440(1)(b)2.,F.A.C]

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

36. Excess Emissions Report: If excess emissions occur (as specified in Condition ~~39~~ 21) for more than two hours due to malfunction, the owner or operator shall notify DEP's Northeast District and Northeast

District Branch Offices within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following the format of 40 CFR 60.7, periods of startup, shutdown, fuel switching and malfunction, shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 15 and 20. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1999 version)].

MONITORING REQUIREMENTS

37. Continuous Monitoring System (CEMS): The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from these units. Upon request from EPA or DEP, the CEMS emission rates for NO_X on the CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1998 version)].

38. Maintenance of CEMS: The CEMS shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. [40CFR60.13]

39. CEMS for Reporting Excess Emissions: The NOx CEMS shall be used to determine periods of excess emissions. For purposes of reporting, one-hour periods when NOx emissions are above 9/42 ppmvd @ 15 % oxygen while firing natural gas/fuel oil shall be reported as excess emissions in accordance with Condition 36. CEMS downtime shall be calculated and reported according to the requirements of 40 CFR 60.7 (c)(3) and 40 CFR 60.7 (d)(2). Periods when short-term NO_X emissions [i.e., ~~30-day block average (gas) and 3-hour block average (oil)~~ 720 operating hour block average] or the annual total (i.e., 133 TPY calendar year)] are above the emission limitations listed in Specific Condition No. 15., shall be reported to the DEP Northeast District Office and Northeast District Branch Office within one working day (verbally) followed up by a written explanation postmarked not later than three (3) working days (alternatively by facsimile within one working day). [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1999 version)].

Comment: In order to simplify reporting

40. CEMS in lieu of Water to Fuel Ratio: The NO_X CEMS shall be used in lieu of the fuel bound nitrogen levels and water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1999 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1999 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS.

41. CEMS Certification and Quality Assurance Requirements: The monitoring devices shall comply with the certification and quality assurance, and any other applicable requirements of Rule 62-297.520, F.A.C., 40 CFR 60.13, including certification of each device in accordance with 40 CFR 60, Appendix

B, Performance Specifications and 40 CFR 60.7(a)(5) or 40 CFR Part 75. Quality assurance procedures must conform to all applicable sections of 40 CFR 60, Appendix F or 40CFR75. The monitoring plan, consisting of data on CEM equipment specifications, manufacturer, type, calibration and maintenance needs, and its proposed location shall be provided to the DEP Emissions Monitoring Section Administrator and EPA for review no later than 45 days prior to the first scheduled certification test pursuant to 40 CFR 75.62.

42. Custom Fuel Monitoring Schedule (Natural Gas): Monitoring of the nitrogen content of natural gas is not required because the fuel-bound nitrogen content of the fuel is minimal. Monitoring of the sulfur content of natural gas is not required if the vendor documentation indicates that the fuels meets the definitions of pipeline natural gas or natural gas set forth in (40CFR 72). A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of natural gas or pipeline supplied natural gas.
- SO_2 emissions shall be monitored using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.
- This custom fuel monitoring schedule will only be valid when natural gas or pipeline natural gas is used as a primary fuel. If the primary fuel for this unit is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

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

44. Determination of Process Variables:

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

45. Alternate Methods of Operation: This unit may operate in simple or combined cycle modes.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

RECEIVED

JAN 27 2000

BUREAU OF AIR REGULATION

JAN 21 2000

4 APT-ARB

Mr. A. A. Linero, P.E.
Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJ: Preliminary Determination and Draft PSD Permit for
Gainesville Regional Utility - Kelly Generating Station (PSD-FL-276)
located in Alachua County, Florida

Dear Mr. Linero:

Thank you for sending the preliminary determination and draft prevention of significant deterioration (PSD) permit for GRU - Kelly Generating Station dated December 17, 1999. The preliminary determination is for the repowering project which will add one combined cycle combustion turbine (CT) with a nominal generating capacity of 83 MW and a 50 MW unfired heat recovery steam generator (HRSG) to be located at the existing J. R. Kelly Generating Station. The project also includes shutting down the existing steam boiler for Unit 8 and routing the HRSG steam to the Unit 8 steam generator. The combustion turbine proposed for the facility is a General Electric (GE), frame 7EA unit. The CT will primarily combust pipeline quality natural gas with No. 2 fuel oil combusted as backup fuel. As proposed, the CT will be allowed to fire natural gas up to 8,760 hours per year and fire No. 2 fuel oil a maximum of 1,000 hours per year. The draft PSD permit contains a condition which limits the total annual emissions of NO_x from the CT to 133 tons per year and allows GRU - Kelly to avoid PSD review for NO_x. Total net emissions from the proposed project are above the thresholds requiring PSD review for carbon monoxide (CO) and particulate matter (PM_{10}).

Based on our review of the preliminary determination and draft PSD permit, we do not have any additional comments beyond those previously submitted during our review of the PSD application. If you have any questions or concerns, please direct them to either Katy Forney at 404-562-9130 or Jim Little at 404-562-9118.

Sincerely,

Douglas Neeley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

CC: M. Kurtz, GRU
NED
T. Davis, EdT
P. Reynolds, NEDB

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning

VIA AIRBORNE EXPRESS

January 21, 2000

RECEIVED

JAN 24 2000

BUREAU OF AIR REGULATION

Mr. Alvaro Linero, P.E.
Administrator, New Source Review Section
Dept. of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 23
Tallahassee, FL 32301

RE: DEP File No. 0010005-002-AC (PSD-FL-276)
J.R. Kelly Generating Station - Combined Cycle Project

Dear Mr. Linero:

Enclosed are Gainesville Regional Utilities' comments on the Draft PSD Permit No. PSD-FL-276, the Best Available Control Technology Determination (BACT) incorporated as Appendix BD and the General Permit Conditions (Appendix GC). GRU's suggested revisions are indicated in red type; rationale for the revisions is indicated in blue.

Please call me at (352) 334-3400 Ext. 1284 if you have any questions or need additional information.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: D. Beck
D. DuBose
M. Kurtz
S. Manasco
G. Swanson
JRK CC1

CC1GRUcommentPSD.y33

GRU

GAINESVILLE REGIONAL UTILITIES
Strategic Planning

VIA AIRBORNE EXPRESS

January 21, 2000

Mr. Alvaro Linero, P.E.
Administrator, New Source Review Section
Dept. of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 23
Tallahassee, FL 32301

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Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

RECEIVED

JAN 24 2000

BUREAU OF AIR REGULATION

xc: D. Beck
D. DuBose
M. Kurtz
S. Manasco
G. Swanson
JRK CC1

CC1GRUcommentPSD.y33

P.O. Box 147117, Station A136, Gainesville, Florida 32614-7117, Phone: (352) 334-3400 ext. 1260 Fax: (352) 334-3151

PERMITTEE:

Gainesville Regional Utilities (GRU)
Post Office Box 147117 (A134)
Gainesville, Florida 32601-7060

Permit No.	PSD-FL-276
File No.	0010005-002-AC
SIC No.	4911
Expires:	December 31, 2001

Authorized Representative:

Michael L. Kurtz – General Manager

PROJECT AND LOCATION:

Air Construction Permit pursuant to the requirements for the Prevention of Significant Deterioration of Air Quality (PSD Permit) for the construction of: a nominal 83 megawatt (MW) natural gas and No. 2 distillate fuel oil-fired combustion turbine-electrical generator; an unfired heat recovery steam generator (HRSG); a ~~100~~ 102 foot stack for combined cycle operation; a ~~78~~ 88 foot bypass stack for simple cycle operation and ancillary equipment. Steam produced by the HRSG will be routed to the existing Unit No. 8 steam turbine-electrical generator to generate 40-50 MW of additional electricity. The combustion turbine may be equipped with inlet air conditioning devices (e.g., evaporative chillers, foggers, etc.). This unit is designated as Combined Cycle Unit CC-1 and will be located at the J.R. Kelly Generating Station, 605 Southeast 3rd Street in Gainesville, Alachua County. UTM coordinates are: Zone 17; 372.0 km E; 3,280.2 km N.

Comment: Stack heights were raised in the final design. Air modelling was conducted using the lower and more conservative heights.

STATEMENT OF BASIS:

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

Attached Appendices and Tables made a part of this permit:

Appendix BD	BACT Determination
Appendix GC	Construction Permit General Conditions

Howard L. Rhodes, Director
Division of Air Resources
Management

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT PSD-FL-276

SECTION I - FACILITY INFORMATION

FACILITY DESCRIPTION

This existing GRU J.R. Kelly Generating Station consists of: three natural gas and distillate fuel oil-fired nominal 16 MW simple cycle combustion turbine-electrical generators designated as Combustion Turbine Nos. 1, 2, and 3; two natural gas and No. 6 fuel oil-fired conventional boilers designated as Units 7 and 8; one natural gas-fired conventional boiler designated as Unit 6 (in cold standby); a recirculating cooling tower system, including two fresh-water mechanical draft cooling towers; fuel oil storage tanks; water treatment facilities, and ancilliary support equipment. The steam turbine-electrical generators associated with Units 6, 7 and 8 have nameplate ratings of 19, 25 and 50 MW respectively.

Unit No. 8 boiler will cease operation following completion of construction of Combined Cycle Unit CC-1.

NEW EMISSION UNIT

This permit addresses the following emission unit:

EMISSION UNIT	SYSTEM	EMISSION UNIT DESCRIPTION
009	Power Generation	Unit CC-1. One ~~nominal~~ dual fuel nominal 133 Megawatt Combined Cycle Combustion Turbine-Electrical Generator with unfired HRSG.

REGULATORY CLASSIFICATION

The facility is classified as a Major or Title V Source of Air Pollution as defined in Rule 62-210.200. It is within an industry included in the list of the 28 Major Facility Categories per Table 62-212.400-1, F.A.C. and is a Major Facility with respect to Rule 62-212.400, Prevention of Significant Deterioration (PSD).

PSD review and a Best Available Control Technology (BACT) determination were required and performed for this project for emissions of carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}). The new Combined Cycle Unit CC-1 is subject to the New Source Performance Standard for Stationary Gas Turbines at 40CFR60, Subpart GG.

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

This project is not subject to the requirements of Chapter 403, Part II, F.S., Electrical Power Plant and Transmission Line Siting because the steam electric generating capacity of this facility will not change.

RELEVANT DOCUMENTS:

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

- Application received September 7, 1999
- Department letter to GRU dated October 6, 1999
- Comments from the Fish and Wildlife Service dated October 6, 1999
- GRU letters dated October 25, November 10, December 2, and December 16, 1999
- Public Notice Package including Technical Evaluation and Preliminary Determination dated December 17, 1999
- Letters from EPA Region IV dated November 10 and ___?___ 1999

- Department's Final Determination and BACT determination issued with this Final Permit.

SECTION II - ADMINISTRATIVE REQUIREMENTS

1. Regulating Agencies: All documents related to applications for permits to construct, operate or modify an emissions unit should be submitted to the Bureau of Air Regulation (BAR), Florida Department of Environmental Protection (FDEP), at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400 and phone number (850) 488-0114. All documents related to reports, tests, and notifications should be submitted to the DEP Northeast District Office 7825 Baymeadows Way, Suite 200B, Jacksonville, Florida 32256-7590 and phone number 904/448-4300 and Northeast District Branch Office, 101 NW 75 Street, Suite 3 Gainesville, Florida 32607 and phone number 352/333-2850.

2. General Conditions: The owner and operator is subject to and shall operate under the attached General Permit Conditions G.1 through G.15 listed in Appendix GC of this permit. General Permit Conditions are binding and enforceable pursuant to Chapter 403 of the Florida Statutes. [Rule 62-4.160, F.A.C.]

3. Terminology: The terms used in this permit have specific meanings as defined in the corresponding chapters of the Florida Administrative Code.

4. Forms and Application Procedures: The permittee shall use the applicable forms listed in Rule 62-210.900, F.A.C. and follow the application procedures in Chapter 62-4, F.A.C. [Rule 62-210.900, F.A.C.]

5. Modifications: The permittee shall give written notification to the Department when there is any modification to this facility as defined in Rule 62-210.200 F.A.C.. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change. [Chapters 62-210 and 62-212, F.A.C.]

6. Construction Expiration: Approval to construct shall become invalid if construction is not commenced within 18 months after receipt of such approval, or if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Department may extend the 18-month period upon a satisfactory showing that an extension is justified. [Rules 62-4.210(2)(3), 62-210.300(1)(a), 62-4.070(3), F.A.C ~~and 40 CFR 52.21(r)(2)~~]

   Comment: Florida has an "approved" not "delegated" program. The authority contained in 40 CFR 52.21(r)(2) does not extend to "approved" programs.

7. ~~BACT Determination: In conjunction with extension of the 18 month periods to commence or continue construction, or extension of the December 31, 2001 permit expiration date, the permittee may be required to demonstrate the adequacy of any previous determination of best available control technology for the source. [Rule 62-4.070(3) F.A.C., 40 CFR 52.21(j)(4)]~~

   Comments: This paragraph should be deleted in its entirety because:

   - Florida has an "approved" not "delegated" program and the authority contained in 40 CFR 52.21(j)(4) does not extend to "approved" programs. Furthermore, the referenced rule applies to phase construction projects. Construction on this project will be continuous (barring unforeseen circumstances).

   - There is no regulatory basis for requiring a BACT re-evaluation upon extension of the permit expiration date especially where construction may already be underway and simply experiencing unforeseen events (e.g., weather or equipment delivery delays) that necessitate extension of the permit.

8. Permit Extension: The permittee, for good cause, may request that this PSD permit be extended. Such a request shall be submitted to the Bureau of Air Regulation 30 days prior to the expiration of the permit, if possible (Rule 62-4.080, F.A.C.).

   Comment: The referenced rule requires that a request be made on a "timely" basis. There may be circumstances where the 30 day prior notice may not be possible in every situation.

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

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

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

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

13. Stack Testing Facilities: Stack sampling facilities shall be installed in accordance with Rule 62-297.310(6), F.A.C. The permittee shall design this unit to accommodate adequate testing and sampling locations for compliance with the applicable emission limits listed in Specific Conditions No. 15 through 17. [Rule 62-4.070(3), Rule 62-297.310 (6) F.A.C.]

14. Semi-annual Reports: Semi-annual excess emission reports, in accordance with 40 CFR 60.7 (a)(7)(c) (1999 version), shall be submitted to the DEP's Northeast District and Northeast District Branch Offices. Each excess emission report shall include the information required in 40 CFR 60.7(c) and 60.334, except as otherwise specified herein (See Specific Condition 39). Excess emission reports may be submitted on a quarterly basis at the permittee's discretion.

APPLICABLE STANDARDS AND REGULATIONS:

1. NSPS Requirements – Subpart GG: The Unit shall comply with all applicable provisions of 40CFR60, Subpart GG, Standards of Performance for Stationary Gas Turbines, adopted by reference in Rule 62-204.800(7)(b), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies when determining compliance with the emissions limitations specified therein.

2. NSPS Requirements – Subpart A: These emission units shall comply with all applicable requirements of 40CFR60, Subpart A, General Provisions including:

   40CFR60.7, Notification and Recordkeeping
   40CFR60.8, Performance Tests
   40CFR60.11, Compliance with Standards and Maintenance Requirements
   40CFR60.12, Circumvention
   40CFR60.13, Monitoring Requirements
   40CFR60.19, General Notification and Reporting requirements

3. BACT Requirements: This emissions unit is subject to Best Available Control Technology (BACT) emissions limits for carbon monoxide (CO) and particulate matter smaller than 10 microns (PM_{10}).

4. Applicable Regulations: Unless otherwise indicated in this permit, the construction and operation of the subject emission unit(s) shall be in accordance with the capacities and specifications stated in the application. The facility is subject to all applicable provisions of Chapter 403, F.S. and Florida Administrative Code Chapters 62-4, 62-17, 62-204, 62-210, 62-212, 62-213, 62-214, 62-296, and 62-297; and the applicable requirements of the Code of Federal Regulations (CFR) Title 40, Parts 51, 52, 60, 72, 73, and 75, adopted by reference in Rule 62-204.800, F.A.C. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements or regulations. [Rule 62-210.300, F.A.C.]

GENERAL OPERATION REQUIREMENTS

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

6. Combustion Turbine Capacity: The maximum heat input rates, based on the Hhigher heating value (HHV) of each fuel to this Unit at ambient conditions of 20°F temperature, 60% relative humidity, 100% load, and 14.7 psi pressure shall not exceed 1,083 million Btu per hour (mmBtu/hr) when firing natural gas, nor 1,121 mmBtu/hr when firing No. 2 or superior grade of distillate fuel oil. These maximum heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Manufacturer's curves corrected for site conditions or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) within 45 days of completing the initial compliance testing. [Design, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

   {Permitting note: The heat input rates have been placed in the permit to identify the capacity of the emission unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emission's unit rate capacity (or to limit future operation to 105 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability. The owner or operator is expected to determine heat input whenever emission testing is required in order to demonstrate what percentage of the rated capacity that the unit was tested. Such heat input determinations may be based on measurements of fuel consumption by various methods including but not limited to fuel flow metering or tank drop measurements, using the heating value of the fuel determined by the fuel vendor or the owner or operator.}

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

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

9. Operating Procedures: Operating procedures shall include good operating practices in accordance with the guidelines and procedures as established by the equipment manufacturers to control emissions. [Rule 62-4.070(3), F.A.C.]

10. Hours of Operation: Combined Cycle Unit 1 may operate 8760 hours per year of which no more than 1000 hours per year may be on distillate fuel oil (0.05% S content). The unit may not operate in excess of the annual nitrogen oxides (NO_X) emission cap described in Specific Condition 15 below. [Applicant Request, Rule 62-210.200, F.A.C. (Definitions - Potential Emissions)]

CONTROL TECHNOLOGY

11. DLN Combustion Technology: The permittee shall install, tune, operate and maintain Dry Low NO_X combustors on this combustion turbine. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific DLN system prior to commencement of operation. [Rule 62-4.070 ~~and 62-210.650~~, F.A.C.]

    Comment: Rule 62-210.650 is redundant - Condition 14 addresses circumvention.

12. Water Injection: The permittee shall install, calibrate, maintain and operate an automated water injection system for ~~each~~ the unit for use when firing fuel oil. The permittee shall provide manufacturer's emissions performance versus load diagrams for the specific water injection system prior to commencement of operation. [Rule 62-4.070, ~~and 62-210.650,~~ F.A.C.]

    Comment: Rule 62-210.650 is redundant - Condition 14 addresses circumvention.

13. Combustion Controls: The permittee shall employ "good operating practices" in accordance with the manufacturer's recommended operating procedures to control CO~~,~~ and NO_X~~, and VOC~~ emissions. Prior to the required initial emissions performance testing, the combustion turbine, the DLN-1 combustors, and the control system shall be tuned to comply with the CO~~,~~ and NO_X~~, and VOC~~ emission limits. Thereafter, these systems shall be maintained and tuned, as necessary, in accordance with manufacturer's recommendations for emissions control ~~comply with the permitted emission limits.~~ [Design, Rules 62-4.070 (3) and 62-212.400, F.A.C.]

Comment:

- VOCs are not regulated by the Subpart GG NSPS nor were they subject to PSD review. GRU suggests that reference to them be deleted since there does not appear to be a regulatory basis for their inclusion.
- The unit was specified, designed and guaranteed to run well-below the applicable NSPS limits. Therefore, the manufacturer's recommendations for tuning and maintenance will be geared towards operating the unit as designed and as contractually specified by GRU, notwithstanding the NSPS limits.

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

EMISSION LIMITS AND STANDARDS

The following emission limits and standards shall apply upon completion of the initial compliance tests, performance tests and certification tests, as applicable and per pollutant.

15. Nitrogen Oxides (NO_X) Emissions:

a) Short-term limits

Nitrogen oxides emissions shall be limited to 97.3/93.0 ppmvd at 15% O2 when firing natural gas and distillate fuel oil, respectively, and when fuel bound nitrogen levels (FBN) are less than or equal to 0.015 percent. For higher fuel bound nitrogen values, the allowance and the adjusted standard shall be determined as follows:

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

where:

STD = allowable NOx emissions (percent by volume at 15% oxygen and on a dry basis)

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NOx emission allowance for fuel-bound nitrogen as defined below:

Fuel-Bound Nitrogen (% by Weight)	F (NO_X % by Volume)
$0 < N \leq 0.015$	0
$0.015 < N < 0.1$	0.04 (N)
$0.1 < N < 0.25$	0.004 + 0.0067(N-0.1)
$N > 0.25$	0.005

where: N= the nitrogen content of the fuel (% by weight)

[Rule 62-204.800(7)(b), F.A.C.]

- ~~Natural Gas Operation. The concentration of NO_X in the stack exhaust gas shall not exceed 9 ppmvd at 15% O_2 on a 30 day rolling average. Compliance will be demonstrated by the continuous emission monitor system (CEMS). Emissions of NO_X in the stack exhaust shall not exceed 32 pounds per hour (lb/hr at ISO conditions) to be demonstrated by initial stack test. [Rule 62-4.070(3) F.A.C.]~~

- ~~Fuel Oil Operation. The concentration of NO_X in the stack exhaust gas shall not exceed 42 ppmvd at 15% O_2 on a 3 hour rolling average. Compliance will be demonstrated by the CEMS. Emissions of NO_X shall not exceed 166 lb/hr (at ISO conditions) to be demonstrated by initial stack test. [Rule 62-212.400, F.A.C.]~~

Comment: BACT was not triggered for NOx and the Department has acknowledged that the 9/42 ppmvd at 15% O2 are vendor guarantees and not emission limitations. Therefore, the applicable emission standards are the New Source Performance Standards as set forth in 40 CFR 60, Subpart GG and as adopted by the Department in Rule 62-204.800(7)(b). Notwithstanding these limits, the unit has been designed and guaranteed to have emissions significantly lower than the NSPS.

b) Annual Emission Cap. Total emissions of NO_X shall not exceed 133 tons on a ~~consecutive 365-day~~ calendar year basis~~, rolled daily~~. The annual emission cap shall not be pro-rated if the unit is operated less than 12 months in any calendar year. Compliance will be demonstrated by the CEMS. [Applicant Request to avoid~~, Rule 62-4.070, F.A.C., escape~~ PSD requirements of Rule 62-212.400, F.A.C., Rule 62-4.070, F.A.C.]

Comment: Language was added for clarification.

16. Carbon Monoxide (CO) Emissions:

- Natural Gas – First Year. During only the first year of operation, the concentration of CO in the stack exhaust while operating on natural gas shall not exceed 25 ppmvd~~. Emissions of CO shall not exceed~~ (For informational purposes the equivalent emission rate is 54 lb/hr (at ISO conditions)). Compliance shall be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

- Natural Gas (Second Year and Beyond) or Fuel Oil. The concentration of CO in the stack exhaust shall not exceed 20 ppmvd ~~at 15% O_2 percent oxygen. Emissions of CO shall not exceed~~ (For information purposes the equivalent emission rate is 43 lb/hr (at ISO conditions)). Compliance shall be demonstrated by a stack test using EPA Method 10. [Rule 62-212.400, F.A.C.]

Comment: The mass emission rate is provided for informational purposes to simplify the permit and any future potential issues associated with periodic monitoring requirements.

~~17. Volatile Organic Compounds (VOC) Emissions: The concentration of VOC (methane equivalent) in the stack exhaust gas while burning natural gas (fuel oil) shall not exceed 1.4 (3.5) ppmvw. Emissions of VOC while burning natural gas (fuel oil) shall not exceed 1.8 (4.5) lb/hr (at ISO conditions) to be demonstrated by initial stack test using EPA Method 18, 25 or 25A. [Rule 62-212.400, F.A.C.]~~

Comment: VOCs were not subject to PSD review - the regulatory reference is not applicable. Also, VOCs are not regulated under NSPS, Subpart GG. GRU suggests that this condition be deleted since there does not appear to be a regulatory basis for it.

18. Sulfur Dioxide (SO_2) emissions: SO_2 emissions shall be limited by firing pipeline natural gas (sulfur content less than 20 grains per 100 standard cubic foot) or by firing No. 2 or superior grade distillate fuel oil with a maximum 0.05 percent sulfur for up to 1000 hours per year. Compliance with this requirement in conjunction with implementation of the Custom Fuel Monitoring Schedule in Specific Conditions 42 and 43 will demonstrate compliance with the applicable SO2 NSPS ~~SO_2~~. [40CFR60 Subpart GG and Rules 62-4.070(3), and 62-204.800(7), F.A.C.]

19. Particulate Matter (~~PM/~~PM_{10}) ~~PM/~~ For informational purposes, PM_{10} emissions shall not exceed 5 lb/hr when operating on natural gas and shall not exceed 10 lb/hr when operating on fuel oil. Visible emissions testing shall serve as a surrogate for ~~PM/~~PM_{10} compliance testing. [Rule 62-212.400, F.A.C.]

    Comment:

    - BACT was not triggered for PM.
    - The mass emission rate is provided for informational purposes to simplify the permit and any future potential issues associated with periodic monitoring requirements.

20. Visible emissions (VE): VE emissions shall serve as a surrogate for ~~PM/~~PM_{10} emissions from the combustion turbine and shall not exceed 10 percent opacity from the stack in use. [Rules 62-4.070 (3), 62-212.400 F.A.C.]

EXCESS EMISSIONS

21. Excess Emissions Allowed: Excess emissions resulting from startup, shutdown, fuel switching or malfunction shall be permitted provided that best operational practices are adhered to and the duration of excess emissions shall be minimized. Excess emissions occurrences shall in no case exceed two hours in any 24-hour period except as follows:

- During "cold start-up" to combined cycle plant operation up to four hours of excess emissions are allowed.
- During shutdowns from combined cycle operation, up to three hours of excess emissions are allowed.
- Unless authorized by the Department.

    Excess NOx emissions are defined as one-hour periods when NOx emissions are above ~~9/42 ppmvd @ 15% oxygen while firing natural gas and fuel oil, respectively~~ the short-term standards set forth in Specific Condition 15.a.

    Cold start-up is defined as a startup that occurs after a complete shutdown lasting at least 48 hours.

    NO_X CEM data shall be recorded and included in calculating the annual NO_X emissions cap.

    [Applicant Request, G.E. Combined Cycle Startup Curves Data and Rule 62-210.700, F.A.C.].

    Comment: For clarification and permit consistency.

22. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup,

shutdown or malfunction, shall be prohibited pursuant to Rule 62-210.700, F.A.C. ~~These excess emissions shall be included in the 30-day rolling average (gas) and the 3-hr average (oil) for NO_X.~~

COMPLIANCE DETERMINATION AND TESTING REQUIREMENTS

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

24. Annual, Initial and Performance Testing: Initial (I) performance tests (for both fuels) shall be performed by the deadlines in Specific Condition 23. ~~Initial tests shall also be conducted after any substantial modifications (and shake down period not to exceed 100 days after re-starting the CT) of air pollution control equipment such as change of combustors.~~ Year two (YR2) compliance testing for CO shall be performed in the second year of operation. Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.310(7), F.A.C., on this units as indicated. The following reference methods shall be used. No other test methods may be used for compliance testing unless prior DEP approval is received in writing.

- EPA Reference Method 9, "Visual Determination of the Opacity of Emissions from Stationary Sources" (I, A). Annual testing is applicable to fuel oil and only if fuel oil is used for more that 400 hours during the preceding 12-month period.
- EPA Reference Method 10, "Determination of Carbon Monoxide Emissions from Stationary Sources" (~~YR2 gas only,~~ I and A (YR2 and beyond, gas only)).
- EPA Reference Method 20, "Determination of Oxides of Nitrogen Oxide, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines." Initial test only for compliance with 40CFR60 Subpart GG. Test data shall be corrected to ISO conditions.
- ~~EPA Reference Method 18, 25 and/or 25A, "Determination of Volatile Organic Concentrations." Initial test only.~~

Comment:

- It is not clear what constitutes a "substantial modification" of air pollution control equipment. A change of combustors is given as an example but does this refer to a change of all combustors or just one or more combustors? Same type combustors or different ones? Over time, combustion equipment changes/replacements may be necessary but may not necessarily have an impact on emissions. However, since emission control is integral to the combustion process these could be interpreted to be subject to this requirement. GRU believes this provision should be deleted because it is too subjective and does not have a regulatory basis.
- To clarify that after the initial CO compliance test, the subsequent annual compliance tests are to be conducted only while burning natural gas.
- There is no regulatory basis for VOC testing requirements.

~~25. Continuous Compliance with the NO_X Emission Limits:~~

- ~~Continuous compliance with the NO_X emission limits shall be demonstrated with the CEM system based on the applicable averaging time of 30-day rolling average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each operating day and a new average emission rate is calculated from the arithmetic average of all valid hourly emission rates from the previous 30 days. [Rules 62-4.070 F.A.C., 62-210.700, F.A.C., and 40 CFR 75]~~
- ~~Compliance with the NO_x emission limits when firing oil shall be demonstrated with the CEM system based on a 3-hour rolling average basis. Based on CEMS data, a separate compliance determination is conducted at the end of each 3-hour period and is calculated from the arithmetic average of all valid hourly emission rates during the previous 3-hour period. [Rules 62-4.070(3) F.A.C., 62-210.700, F.A.C., and 40 CFR 75]~~
- ~~A valid hourly emission rate shall be calculated for each hour in which at least two NO_X concentrations are obtained at least 15 minutes apart. Valid hourly emission rates shall not include periods of start up, shutdown, or malfunction unless not authorized by 62-210.700 F.A.C.~~
- ~~Periods when the 30-day rolling average (gas), 3-hr average (oil) or the 365-day rolling average NOx exceeds the emission limitations specified in Condition 15, shall be reported as required by Condition 39.~~

Comment: See comment related to Specific Condition 15.

26. Continuous Compliance with the NO_X Emission Cap: NO_X data collected by the certified CEMS shall be used to demonstrate compliance with the ~~365-day rolling~~ annual NO_X emissions cap (specified in Specific Condition 15) ~~for each calendar day of operation~~ by the following method:
    - For each hour of operation (including startup and shutdown and fuel switching), the NO_X CEMS shall calculate and record the hourly NO_X mass emissions (in units of pounds per hour, rounded to the nearest tenth of a pound). The hourly mass emissions shall be calculated by multiplying the hourly NOx emission rate (in lbs/mmBtu) by the hourly heat input (in mmBtu/hr) and the hourly operating time (in hours). Each hourly emissions rate shall be calculated using at least two valid data points at least 15 minutes apart.
    - ~~For each calendar day of operation, the NO_X CEMS shall calculate and record the daily NOx emissions in units of pounds per day, rounded to the nearest tenth of a pound. Daily emissions rates shall be the sum of all recorded hourly emissions rates.~~
    - ~~For each calendar day of operation, the NO_X CEMS shall calculate and record the 365-day rolling daily total in units of tons, rounded to the nearest hundredth of a ton. The 365-day rolling total shall be the sum of all recorded daily NO_X emissions rates for the applicable 365 consecutive day period calendar year. NO_X emissions shall be recorded as "zero" for any days occurring prior to initial startup of the combustion turbine.~~
    - For each calendar year, NOx mass emissions (in tons) will be calculated as follows:

      NOx (in tons) = (Sum of all hourly NOx mass emissions in lbs)/2000
    - When NOx monitoring data is not available, substitution for missing data shall be handled as required by 40 CFR 75.

    [Rule 62-4.070(3), F.A.C. to avoid requirements of Rule 62-212.400, F.A.C.]

Comment: These procedures are derived from 40 CFR 75.72 and Appendix F, Section 8.4 and will provide for consistency of data in reporting.

27. Compliance with the SO_2 and ~~PM/~~PM_{10} emission limits: Not withstanding the requirements of Rule 62-297.340, F.A.C., the use of pipeline natural gas; is the method for determining compliance for SO_2 and PM_{10}. For the purposes of demonstrating compliance with the 40 CFR 60.333 SO_2 standard, ASTM methods D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel shall be utilized in accordance with the EPA-approved custom fuel monitoring schedule or natural gas supplier data may be submitted or the natural gas sulfur content referenced in 40 CFR 75 Appendix D may be utilized. However, the applicant is responsible for ensuring that the procedures in 40 CFR60.335 or 40 CFR75 are used when determination of fuel sulfur content is made. Analysis may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor, or any other qualified agency pursuant to 40 CFR 60.335(e) (1998 version). [Applicant request]

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

Comment: 40 CFR 75 considers annual testing as once every four successive QA operating quarters (see 40 CFR 75, Appendix B, section 2.3.1.2). A QA operating quarter is defined as a "calendar quarter in which there are at least 168 unit operating hours". Thus, the term "annual" means different things when referencing state compliance testing vs. RATA testing and is potentially confusing.

~~29. Compliance with the VOC emission limit: An initial test is required to demonstrate compliance with the VOC emission limit. Thereafter, the CO and VE limits and periodic tuning data will be employed as surrogates and no annual testing is required.~~

Comment: There is no regulatory basis for this requirement.

30. Testing procedures: Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 90-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air temperature during the test (with 100 percent represented by a curve depicting heat input vs. ambient temperature). If it is impracticable to test at permitted capacity, the source may be tested at less than permitted capacity. In this case, subsequent operation is limited by adjusting the entire heat input vs. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 110 percent of the value reached during the test until a new test is conducted.

    Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Procedures for these tests shall meet all applicable requirements (i.e., testing time frequency, minimum compliance duration, etc.) of Chapters 62-204 and 62-297, F.A.C. [Regulatory reference ?]

31. Test Notification: The DEP's Northeast District and Northeast District Branch Offices shall be notified, in writing, at least 30 days prior to the initial performance tests and at least 15 days before annual compliance test(s). [Regulatory reference ?]

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

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

NOTIFICATION, REPORTING, AND RECORDKEEPING

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

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

36. Excess Emissions Report: If excess emissions occur (as specified in Condition 39) for more than two hours due to malfunction, the owner or operator shall notify DEP's Northeast District and Northeast District Branch Offices within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident. Pursuant to the New Source Performance Standards, all excess emissions shall also be reported in accordance with 40 CFR 60.7, Subpart A. Following ~~this~~ the format of 40 CFR 60.7, periods of startup, shutdown, fuel switching and malfunction~~,~~ shall be monitored, recorded, and reported as excess emissions when emission levels exceed the permitted standards listed in Specific Condition No. 15 ~~through 17~~ and 20. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C., and 40 CFR 60.7 (1999 version)].

    Comment: Excess emission reporting would be applicable to NOx and opacity only since they are the pollutants addressed by this permit that will be/could be continuously or periodically monitored without a stack test.

MONITORING REQUIREMENTS

37. Continuous Monitoring System (CEMS): The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from these units. Upon request from EPA or DEP, the CEMS emission rates for NO_X on the CT shall be corrected to ISO conditions to demonstrate compliance with the NO_X standard established in 40 CFR 60.332. [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1998 version)].

38. Maintenance of CEMS: The CEMS shall be in continuous operation except for breakdowns, repairs, calibration checks, and zero and span adjustments. The CEMS shall meet minimum frequency of operation requirements: one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. Data recorded during periods of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data average. [40CFR60.13]

39. CEMS for Reporting Excess Emissions: The NOx CEMS ~~NOx~~ shall be used to determine periods of excess emissions. One-hour periods when NOx emissions are above ~~9/42 ppmvd @ 15 % oxygen while firing natural gas and fuel oil , respectively~~ the short-term emission standards specified in Specific Condition 15.a shall be reported as excess emissions in accordance with Condition 36. CEMS downtime shall be calculated and reported according to the requirements of 40 CFR 60.7 (c)(3) and 40 CFR 60.7 (d)(2). Periods when ~~short-term~~ NO_X emissions ~~(i.e., 30-day rolling average (gas) and 3-hour average (oil) or the annual total (i.e., 365-day rolling average)~~ are above the emission limitations listed in Specific Condition No 15. a or b, shall be reported to the DEP Northeast District Office and Northeast District Branch Office within one working day (verbally) followed up by a written explanation postmarked not later than three (3) working days (alternatively by facsimile within one working day). [Rules 62-204.800, 62-210.700, 62-4.130, 62-4.160(8), F.A.C and 40 CFR 60.7 (1999 version)].

40. CEMS in lieu of Water to Fuel Ratio: ~~Subject to EPA approval, t~~The NO_X CEMS shall be used in lieu of the fuel bound nitrogen levels and water/fuel monitoring system for reporting excess emissions in accordance with 40 CFR 60.334(c)(1), Subpart GG (1999 version). The calibration of the water/fuel monitoring device required in 40 CFR 60.335 (c)(2) (1999 version) will be replaced by the 40 CFR 75 certification tests of the NO_X CEMS.

    Comment: EPA approved this proposal by letter from Mr. Doug Neeley (EPA) to Mr. Al Linero (FDEP) dated December 29, 1999.

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

42. Custom Fuel Monitoring Schedule (Natural Gas): ~~Subject to EPA approval,~~ Monitoring of the nitrogen content of natural gas is not required because the fuel-bound nitrogen content of the fuel is minimal. Monitoring of the sulfur content of natural gas is not required if the vendor documentation indicates that the fuels meets the definitions of pipeline natural gas or natural gas set forth in (40CFR 72). A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

    - The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30.
    - The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel of natural gas or pipeline supplied natural gas.
    - SO_2 emissions shall be monitored using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.
    - This custom fuel monitoring schedule will only be valid when natural gas or pipeline natural gas is used as a primary fuel. If the primary fuel for this unit is changed to a higher sulfur fuel, SO_2 emissions must be accounted for as required pursuant to 40 CFR 75.11(d).

Comment: EPA approved the custom fuel monitoring by letter dated from Mr. Doug Neeley (EPA) to Mr. Al Linero (FDEP) dated December 29, 1999.

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

    Comment: EPA approved the custom fuel monitoring by letter dated from Mr. Doug Neeley (EPA) to Mr. Al Linero (FDEP) dated December 29, 1999.

44. Determination of Process Variables:

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

45. Alternate Methods of Operation: This unit may operate in simple or combined cycle modes.

APPENDIX BD
BEST AVAILABLE CONTROL TECHNOLOGY DETERMINATION (BACT)

January 21, 2000
GRU Comments on Appendix BD
Suggested revisions are indicated in red; rationale is provided in blue to the extent it is not already provided in the permit comments.

Gainesville Regional Utilities
J.R. Kelly Generating Station
Combined Cycle Repowering Project

BACKGROUND

The applicant, Gainesville Regional Utilities (GRU), proposes to install a nominal 133 megawatt gas and distillate fuel oil-fired combined cycle unit (Unit CC-1) at the existing J.R. Kelly Generating Station, located near downtown Gainesville, Alachua County. The proposed project will result in "significant increases" with respect to Table 62-212.400-2, Florida Administrative Code (F.A.C.) of emissions of particulate matter (PM_{10}) and carbon monoxide (CO). The project is therefore subject to review for the Prevention of Significant Deterioration (PSD) and a determination of Best Available Control Technology (BACT) in accordance with Rule 62-212.400, F.A.C.

The primary unit to be installed is a nominal 83 MW General Electric PG7121EA (7EA) combustion turbine-electrical generator, fired primarily with pipeline natural gas. The project includes an unfired heat recovery steam generator (HRSG) that will feed the existing Unit 8 steam turbine-electrical generator to produce another 40-50 MW. The project will result in the retirement of the conventional gas and residual fuel oil-fired steam generator that presently feeds the Unit 8 steam turbine-electrical generator. The project includes a ~~100~~ 102 foot stack for combined cycle operation, and a ~~78~~ 88 foot bypass stack for simple cycle operation. Descriptions of the process, project, air quality effects, and rule applicability are given in the Technical Evaluation and Preliminary Determination dated December 18, 1999, accompanying the Department's Intent to Issue.

DATE OF RECEIPT OF A BACT APPLICATION:

The application was received on September 7, 1999 and included a BACT proposal prepared by the applicant's consultant, Environmental Consulting & Technology, Inc. The application was revised on December 16, 1999 to reflect a cap on emissions of nitrogen oxides (NO_X).

REVISED BACT DETERMINATION REQUESTED BY THE APPLICANT:

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
Particulate Matter (PM_{10})	Pipeline Natural Gas 0.05% Sulfur Distillate Oil Combustion Controls	5 lb/hr (gas)* 10 lb/hr (oil, 1000 hrs)* 10 percent Opacity
Carbon Monoxide	Combustion Controls	25 ppmvd (gas – 1st year) 20 ppmvd (gas – after 1st yr) 20 ppmvd (fuel oil)

- Mass emission rates provided for informational purposes.

According to the revised application, Unit CC-1, will emit approximately 133 tons per year (TPY) of NO_X, 189 TPY of CO (after the first year), 9 TPY of VOC, 47 TPY of SO_2, and 24 TPY of PM/PM_{10}. Because of the shutdown of Unit 8 and an emission cap on NO_X, net emissions increases from the facility are projected to be 39 TPY NO_X, 171 TPY of CO (after the first year), 23 TPY of PM/PM_{10}, 18 TPY of SO_2 and 7 TPY of VOC. The basis for these values is 7,760 hours of operation on natural gas and 1,000 hours on distillate fuel oil.

BACT DETERMINATION PROCEDURE:

In accordance with Chapter 62-212, F.A.C., this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the Department of Environmental Protection (Department), on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques. In addition, the regulations state that, in making the BACT determination, the Department shall give consideration to:

- Any Environmental Protection Agency determination of BACT pursuant to Section 169, and any emission limitation contained in 40 CFR Part 60 - Standards of Performance for New Stationary Sources or 40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants.
- All scientific, engineering, and technical material and other information available to the Department.
- The emission limiting standards or BACT determination of any other state.
- The social and economic impact of the application of such technology.

The EPA currently stresses that BACT should be determined using the "top-down" approach. The first step in this approach is to determine, for the emission unit in question, the most stringent control available for a similar or identical emission unit or emission unit category. If it is shown that this level of control is technically or economically unfeasible for the emission unit in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections.

The BACT evaluation should be performed for each emissions unit and pollutant under consideration. In general, EPA has identified five key steps in the top-down BACT process: identify alternative control technologies; eliminate technically infeasible options; rank remaining technologies by control effectiveness; evaluate the most effective controls considering energy, environmental, and economic impacts; and select BACT. A BACT determination must not result in the selection of control technology that would not meet any applicable emission limitation under 40 CFR Part 60 (Standards of Performance for New Stationary Sources) or 40 CFR Part 61 (National Emission Standards for Hazardous Air Pollutants).

STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES:

The minimum basis for a BACT determination is 40 CFR 60, Subpart GG, Standards of Performance for Stationary Gas Turbines (NSPS). Subpart GG was adopted by the Department by reference in Rule 62-204.800, F.A.C. The key emission limits required by Subpart GG are 75 ppmvd NO_X @ 15% O_2 (assuming 25 percent efficiency) and 150 ppm SO_2 @ 15% O_2 (or <0.8% sulfur in fuel). There are no limits for CO or PM_{10} in Subpart GG. PSD was not triggered and a BACT determination is not required for NO_X, ~~or~~ SO_2, PM, VOCs, SAM. No National Emission Standard for Hazardous Air Pollutants exists for stationary gas turbines.

DETERMINATIONS BY STATES:

The following table is a sample of information on recent CO and PM_{10} BACT or emission limits set by Florida and Southeastern States for General Electric 7EA combustion turbines. The GRU project is included for comparison. The first two projects are for simple cycle installations.

Project Location	CO - ppmvd (or lb/mmBtu)	PM - lb/hr (and/or % opacity)	Technology	Comments
FPC Int. City, FL	20 – NG or FO 25 – NG 1st year	10 percent Opacity (basis: 0.002 gr/dscf)	Clean Fuels Good Combustion	3x87 MW GE 7EA 12/99 1000 hrs oil
TECO Hardee, FL	20 – NG or FO 25 – NG 1st year	10 percent Opacity (basis: 0.002 gr/dscf)	Clean Fuels Good Combustion	One 75 MW GE 7EA. 10/99 1000 hrs oil
Olin Cogen, AL	0.07 lb.mmBtu - NG (equals ~ 29 ppmvd))		Clean Fuels Good Combustion	One 80 MW GE 7EA 12/97 DB & PA
GE Plastics Cogen, AL	0.08 lb.mmBtu - NG (equals ~ 33 ppmvd)		Clean Fuels Good Combustion	One 80 MW GE 7EA 5/98 Duct Burner
GRU Gainesville, FL	20 – NG or FO 25 – NG 1st year	5/10 lb/hr - NG/FO 10 percent Opacity	Clean Fuels Good Combustion	One 83 MW GE 7EA Repower 1000 hrs oil

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

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

Natural gas and 0.05 percent sulfur No. 2 (or superior grade) distillate fuel oil will be the only fuels fired and are efficiently combusted in gas turbines. Such fuels are necessary to avoid damaging turbine blades and other components already exposed to very high temperature and pressure. Natural gas is an inherently clean fuel and contains no ash. The fuel oil to be combusted contains a minimal amount of ash and (per the application) will be used for a maximum of 1000 hours per year making any conceivable add-on control technique for ~~PM~~/PM_{10} either unnecessary or impractical. Annual emissions of PM_{10} are expected to be less than 24.4 tons.

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

Comment: PSD review was triggered for PM10 but not PM. Since this is a BACT review, shouldn't the discussion be limited to PSD pollutants only?

REVIEW OF CARBON MONOXIDE(CO) CONTROL TECHNOLOGIES

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

Among the most recently permitted projects with oxidation catalyst requirements are the 500 MW Wyandotte Energy project in Michigan, the El Dorado project in Nevada, Ironwood in Pennsylvania, Millennium in Massachusetts, and Sutter Calpine in California. The permitted CO values of these units are between 3 and 5 ppmvd. Catalytic oxidation was recently installed at a cogeneration plant at Reedy Creek (Walt Disney World), Florida to avoid PSD review which would have been required due to increased operation at low load. Seminole Electric will install oxidation catalyst to meet the permitted CO limit at its planned 244 MW Westinghouse 501FD combined cycle unit in Hardee County, Florida.[1]

Most combustion turbines incorporate good combustion to minimize emissions of CO. These installations are typically permitted to achieve emissions between 10 and 30 ppmvd at full load, even as they achieve relatively low NO_X emissions by SCR or dry low NO_X means. GRU proposes to meet a limit of 20 ppmvd while firing natural gas or fuel oil. GRU requests that it be allowed to initially meet a limit of 25 ppmvd when firing natural gas and to achieve 20 ppmvd after one year. The reason is that GE only offers a guarantee of 25 ppmvd for natural gas on a 7EA unit.

Although GE does not offer a single digit CO guarantee on the 7EA, according to its own reports, CO single-digit emissions have been achieved simultaneously with single-digit NO_X emissions on several MS7001EAs.[2] When the same units are operated at peak power, "expected" CO emissions are 6 ppmvd with an increase of NO_X to 18 ppmvd.

According to recent data reviewed by the Department, actual CO emissions from eight 7E units undergoing conversions to 7EA and DLN-1 technology achieved between 1.3 and 10.5 ppmvd of CO with an average of 5 ppmvd.[3] This was accomplished while the units achieved single-digit NO_X values. The Department expects similar actual performance from the GRU project.

DEPARTMENT BACT DETERMINATION

Following are the BACT limits determined for the GRU project assuming full load.

POLLUTANT	CONTROL TECHNOLOGY	PROPOSED BACT LIMIT
PM_{10}, VE	Pipeline Natural Gas 0.05% Sulfur Distillate Oil Combustion Controls	5 lb/hr (gas)* 10 lb/hr (oil, 1000 hrs)* 10 Percent Opacity
CO	Combustion Controls	25 ppmvd and 54 lb/hr* (gas – 1st year) 20 ppmvd and 43 lb/hr* (gas – after 1st year) 20 ppmvd and 43 lb/hr* (fuel oil)

* Mass emission rates provided for informational purposes.

RATIONALE FOR DEPARTMENT'S DETERMINATION

- The top technology in a top/down analysis for PM_{10} control is good combustion control of inherently clean fuels. No further control methods are available.
- The values of 5 pounds per hour while burning natural gas and 10 lb/hr while burning fuel oil reflect BACT when coupled with a visible emissions limit of 10 percent opacity. The higher 10 lb/hr rate is limited by allowing only 1000 hours of back-up fuel oil use. Most years, fuel oil use will be substantially less than 1000 hours.
- The top technology in a top/down analysis for CO is installation of oxidation catalyst. Use of oxidation catalyst is not widespread except in CO non-attainment areas. It is used in attainment areas when a unit is used that has inherently high emissions of CO.

- GRU's consultant evaluated the use of an oxidation catalyst for the Unit 8 repowering project. The oxidation catalyst control system was estimated to increase the capital cost of the project by $1,324,708 with an annualized cost of $345,352 per unit. GRU consultant's estimated levelized costs for CO catalyst control at 2,029 per ton.
- The Department does not necessarily adopt this estimate, but would agree that these estimates would not be cost-effective for removal of CO (especially if emissions without control are actually much lower than 20 ppmvd as discussed above).
- The Department will set CO limits achievable by good combustion at full load as 25 ppmvd (first year of operation) and 20 ppmvd (gas) and 20 ppmvd (oil). These values are equal to those at the recently permitted 7EA units in Florida. They are similar or slightly higher than values from permitted "F" combustion turbines operating in either combined cycle or simple cycle mode. The reason is that the lower firing temperatures of the 7EA units versus the 7FA units results in less burn-out. As discussed above, the Department expects CO emissions to be in the 5 ppmvd range (even when NO_X emissions are 9 ppmvd), but does not want to force a lower guarantee from GE at an excessive cost to GRU.
- The CO impact on ambient air quality is lower compared to other pollutants because the allowable concentrations of CO are much greater than for NO_X, SO_2, VOC (ozone) or PM_{10}.

COMPLIANCE PROCEDURES

POLLUTANT	COMPLIANCE PROCEDURE
Visible Emissions	Method 9
Particulate (PM_{10})	By VE tests. EPA Method 5 if a special test is needed
Carbon Monoxide	Method 10 ~~(can use RATA if at capacity)~~

Comment: The deleted language conflicts with Specific Condition 28 in the permit and does not appear to be necessary here.

DETAILS OF THE ANALYSIS MAY BE OBTAINED BY CONTACTING:

A. A. Linero, P.E. Administrator, New Source Review Section ____________________
Teresa Heron, Review Engineer, New Source Review Section

Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended By: Approved By:

____________________ ____________________

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

Howard L. Rhodes, Director
Division of Air Resources Management

Date:

Date:

REFERENCES

[1] Letter. Opalinski, M.P., SECI to Linero, A.A., FDEP. Turbines and Related Equipment at Hardee Unit 3. December 9, 1998.

[2] Paper. Davis, L.B., GE. Dry Low NO_X Combustion Systems for GE Heavy-Duty Gas Turbines. 1998.

[3] Paper. Ihfe, L.M., et. al., Texaco P&G. Kern River and Sycamore Cogen Plant Uprates and Emission Compliance. Power-Gen Conference. New Orleans, Louisiana. November 30, 1999.

Gentry, Jodi D

From: Dayhaw, Brandi M
Sent: Wednesday, January 19, 2000 2:12 PM
To: Gentry, Jodi D
Subject: New employee orientation

Ken lazzaro will need to reschedule his orientation, he was scheduled to attend on 1/26/00.

Thank you,
Brandi Dayhaw
Gainesville Regional Utilities
dayhawbm@gru.com
(352)334-3400X1148
fax (352)334-3183

should be 141

G.1 The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.1~~61~~, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

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

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

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

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

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

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

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

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

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

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

CO: Convert lb/mmBTU to PPM

0.07	=	lb/mmBTU
20.9	=	Percent oxygen in the air (%)
7.1	=	Percent moisture in exhaust gas (%)
13.9	=	Percent oxygen in exhaust gas (%)
2116.8	=	Atmospheric pressure of 2116.8 lbf/ft2
1465518	=	Volumetric flow rate in actual cubic feet per minute (acfm)
28	=	Molecular Weight (MW) of pollutant, lb/lb-mol
60	=	60 minutes / hour
1545	=	Universal Gas Constant of 1545 ft-lbf/°R
1459	=	Exhaust gas exit temperature in °R (T,°F + 460)
15	=	Correction to 15% oxygen
1000000	=	Conversion from parts per "million"
880	=	mmBTU / hour, HHV

ppmvd @ 15% O2 = [(lb/mmBTU) x (mmBTU/hr) x (1545) x (Temp.) x (20.9 - 15) x (1000000)] / {[(20.9 x (1 - % H2O/100)) - (% O2, actual)] x (2116.8) x (acfm)x (MW) x (60)}

ppmvd @ 15%O2 = 28.5

All parameters based on 100% base load for natural gas firing with inlet air conditions of 59°F and 60% RH.

DIVISIONS OF FLORIDA DEPARTMENT OF STATE
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Division of Administrative Services
Division of Corporations
Division of Cultural Affairs
Division of Elections
Division of Historical Resources
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Historic Tampa/Hillsborough County Preservation Board
RINGLING MUSEUM OF ART

FLORIDA DEPARTMENT OF STATE
Katherine Harris
Secretary of State
DIVISION OF ELECTIONS

RECEIVED
JAN 20 2000
DIVISION OF AIR
RESOURCES MANAGEMENT

MEMORANDUM

TO: Florida Administrative Weekly Advertisers

FROM: Liz Cloud, Chief
Bureau of Administrative Code

DATE: January 14, 2000

SUBJECT: Invoices for Publications in the Florida Administrative Weekly (FAW)

Please be advised that the invoices for notices printed in the FAW have been revised.

The new invoices are a single sheet with a perforated portion at the bottom of the page, which should be removed and returned with your payment to insure accurate credit to your account. Proof of publication pages will continue to be attached to each invoice.

All invoices should be forwarded to your financial department for payment. Please **do not detach the proof of publication pages from the invoice** before sending it to your financial department for payment. If your office requires more than one copy of the page, please make a copy for your records and send the original to your financial department.

Should you have any questions or problems, please do not hesitate to contact this office.

Thank you.

LC/si

Enclosure

BUREAU OF ADMINISTRATIVE CODE
The Elliot Building • 401 South Monroe Street • Tallahassee, Florida 32399-0250 • (850) 488-8427
FAX: (850) 488-7869 • WWW Address: **http://www.dos.state.fl.us** • E-Mail: *election@mail.dos.state.fl.us*

FLORIDA DEPARTMENT OF STATE
Katherine Harris Secretary of State
Division of Elections
Bureau of Administrative Code
The Elliot Building - 401 South Monroe St. - Tallahassee, Fl. 32399-0250 - (850)488-8427

Billed to:
DEPT OF ENVIRONMENTAL PROTECTION
AIR RESOURCES MANAGEMENT OFFICE
2600 BLAIR STONE ROAD
MAIL STATION 5505
TALLAHASSEE, FL 32399-2400
Attn: SHAROLYN WOOD

Account: 7627 **Invoice Date: 01/14/2000** **Invoice Number: 041519**

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1	Volume:25/52 Pages:5957	28	0.79	$22.12
Invoice # must appear on all checks and correspondence. Please pay balance due:				**$22.12**
F.E.I.D. number: 59-3466865	*** Net Due - 15 days - No Discount ***			

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The Capitol - Room 1901 - Tallahassee, Fl. 32399-0250

Account: 7627 **Invoice Date: 1/11/00** **Number: 41519** **Amount Due: $22.12**

State Agencies - Journal Transfer to Account Code: 45-50-2-561001-45100000-00
Org Code / EO : 4510-3020 R3 Object: 010000 Category: 001903

For Accounting Use Only: Object Code: 019032 Cat: 001903 ARGL: 16300 GL: 67100
Samas Account Code/Vendor: 37-20-2-035001-37550000-00

calendar days prior to the meeting. If you are hearing or speech impaired, please call the Real Estate Appraisal Board using the Florida Dual Party Relay System which can be reached at 1(800)955-8770 (Voice) and 1(800)955-8771 (TDD).

A copy of the agenda may be obtained by writing: Deputy Clerk, Florida Real Estate Appraisal Board, P. O. Box 1900, Orlando, Florida 32802-1900.

The Florida **Real Estate Appraisal Board** announces a meeting to which everyone is invited.

DATE AND TIME: Tuesday, February 1, 2000, 9:00 a.m.

PLACE: Department of Business & Professional Regulation, Division of Real Estate, Room 301, Third Floor, 400 W. Robinson Street, North Tower, Orlando, FL 32801, (407)245-0800

PURPOSE: Official business of the Appraisal Board. Including but not limited to: Rule/statute amendments, and Disciplinary actions.

Any person who decides to appeal a decision made by the Board with respect to any matter considered at this meeting or hearing will need a record of the proceedings and for such purpose, may need to ensure that a verbatim record of the proceedings is made, which record includes testimony and evidence upon which the appeal is based.

Any person requiring a special accommodation at this meeting because of a disability or physical impairment should contact the Real Estate Appraisal Board, (407)245-0800, at least five calendar days prior to the meeting. If you are hearing or speech impaired, please call the Real Estate Appraisal Board using the Florida Dual Party Relay System which can be reached at 1(800)955-8770 (Voice) and 1(800)955-8771 (TDD).

A copy of the agenda may be obtained by writing: Deputy Clerk, Florida Real Estate Appraisal Board, P. O. Box 1900, Orlando, Florida 32802-1900.

DEPARTMENT OF ENVIRONMENTAL REGULATION

The **Department of Environmental Protection** announces a public meeting to which all persons are invited:

DATE AND TIME: January 12, 2000, 7:00 p.m. – 9:00 p.m.

PLACE: Gainesville Regional Utilities Administration Building, Multi-purpose Room, 301 Southeast 4th Avenue, Gainesville, Florida

PURPOSE: To accept public comments and provide status of Department's Intent to Issue an Air Construction Permit to construct a combined cycle combustion turbine-electrical generator at the: Gainesville Regional Utilities, J. R. Kelly Generating Station, 605 Southeast 3rd Street, Gainesville, Alachua County, Florida.

The permitting action is subject to the Department's rules for the Prevention of Significant Deterioration of Air Quality and Best Available Control Technology (BACT).

A copy of the agenda and the Department's proposed permit and supporting documents can be obtained by contacting: Ms. Teresa Heron, Department of Environmental Protection, 2600 Blair Stone Road, MS 5505, Tallahassee, Florida 32399, Telephone (850)921-9529, or by phoning the Bureau of Air Regulation's New Source Review Section, (850)921-9533.

Pursuant to the provisions of the Americans with Disabilities Act, any person requiring special accommodations to participate in this meeting is asked to advise the agency at least 48 hours before the meeting by contacting the Personnel Service Specialist, Bureau of Personnel, (850)488-2996. If you are hearing or speech impaired, please contact the agency by calling 1(800)955-8771 (TDD).

DEPARTMENT OF JUVENILE JUSTICE

The **Department of Juvenile Justice** announces a meeting of The Juvenile Justice Standards and Training Commission to which any interested parties are invited.

DATES AND TIMES: January 12, 2000, 1:00 p.m. – 4:30 p.m.; January 13, 2000, 9:00 a.m. – 4:30 p.m.

PLACE: Radisson Hotel, 415 North Monroe Street, Tallahassee, Florida 32301, Telephone (850)224 6000

PURPOSE: Regular meeting to discuss issues related to staff training for Juvenile justice programs, as well as future plans for the juvenile Justice training system.

A copy of the agenda may be obtained after December 31, 1999 by contacting: Peggy Sanders, Florida Department of Juvenile Justice, Office of Staff Development, 2737 Centerview Drive, Suite 114, Tallahassee, Florida 32399-3100, Telephone (850)488-8825.

The **Juvenile Justice Accountability Board** announces a meeting of it's Juvenile Justice Education Policy Task Force which is open to the public.

DATES AND TIME: January 12, 2000, 2:00 p.m.– 6:00 p.m.; January 13, 2000, 8:30 a.m. – 4:00 p.m., or adjournment, whichever is earlier

PLACE: Webster Building, Second Floor, Conference Room, 2671 Executive Center Circle, West, Tallahassee, Florida

GENERAL SUBJECT MATTER TO BE CONSIDERED: Includes vocational programming for youth committed to the Department of Juvenile Justice, implementation of Task Force's recommendations in HB 349, school district accountability and funding, and the programmatic, fiscal and governance issues associated with the creation of a separate school district.

For more information, contact: Marianna Tutwiler, Juvenile Justice Accountability Board Office, (850)921-5274.

The **Juvenile Justice Accountability Board** announces a meeting which is open to the public.

Air Quality Monitoring Sites in Alachua County Operated by ACEPD, and FDEP and the City of Gainesville

ACEPD Monitoring Sites

NOx, SO2 and Ozone

PM2.5 and PM10

Note: These sites are operated exclusively by ACEPD as part of an air quality study

FDEP Monitoring Sites

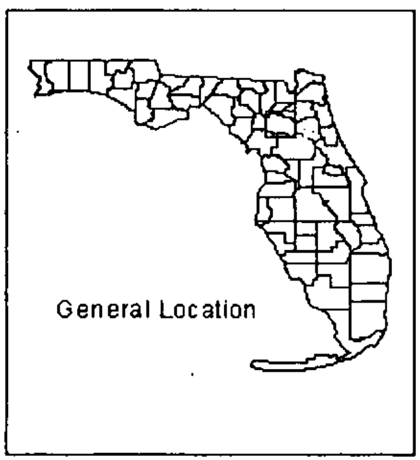
Ozone

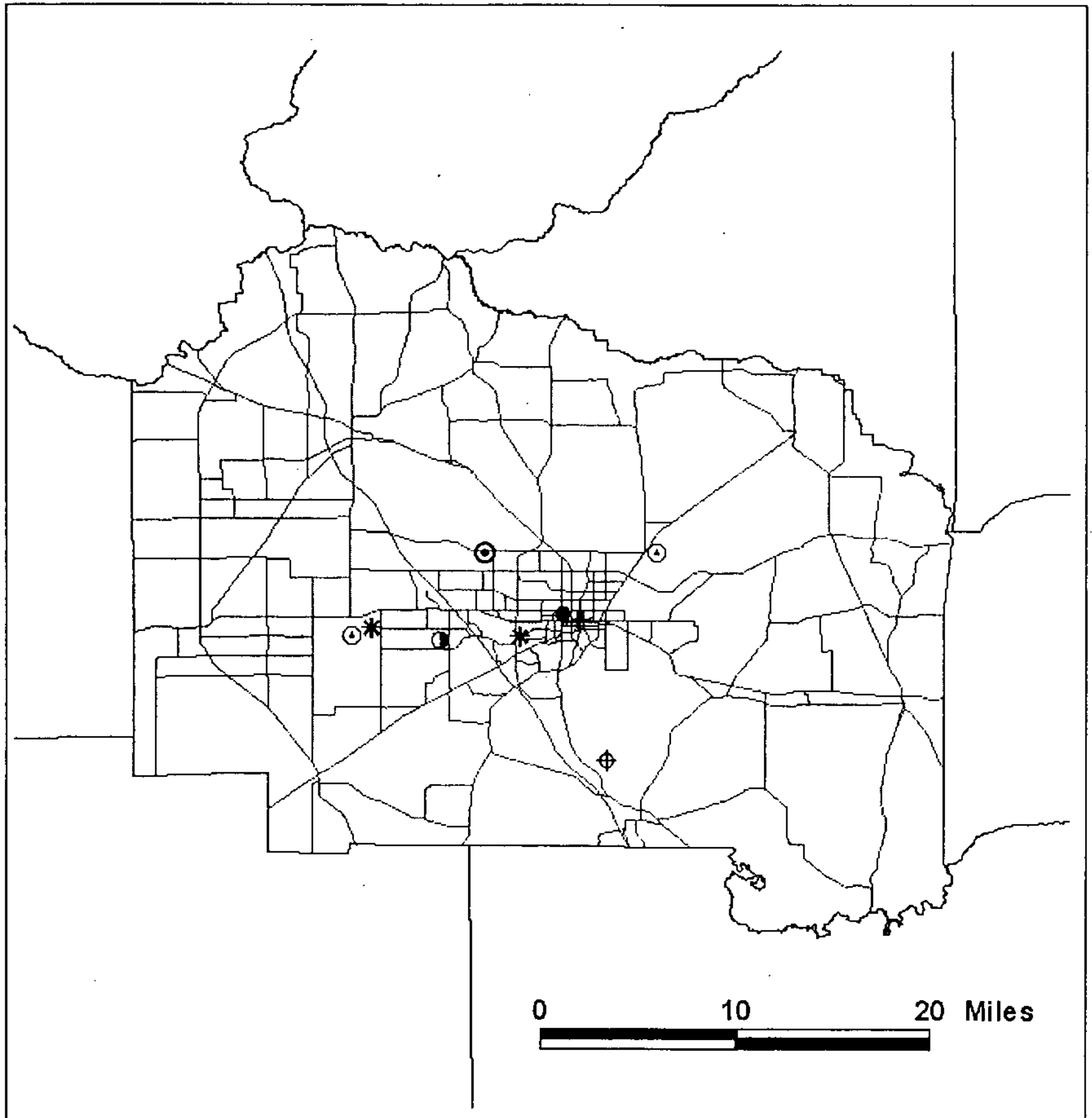
PM2.5 and PM10

PM2.5

PM10

Note: These sites are operated by FDEP and are part of a state-wide air monitoring network. The City of Gainesville and FDEP jointly operate the single PM2.5 monitor in western Alachua County.





PUBLIC MEETING ANNOUNCEMENT

AGENCY: Florida Department of Environmental Protection

PURPOSE: Receive comments from the public on the Department's proposed air construction permit to be issued to Gainesville Regional Utilities. This permit is for the construction of a new nominal 83-megawatt natural gas and distillate fuel oil fired combustion turbine generator at the existing J.R. Kelly generating Station in Gainesville, Alachua County, Florida.

DATE: January 12, 2000

TIME: 7:00 p.m.

PLACE: GRU Administration Building, Multi-purpose Room, 301 Southeast 4th Avenue, Gainesville.

MEETING AGENDA

7:00 p.m. Introduction/Moderator

- *Clair H. Fancy, P.E., Bureau of Air Regulation, FDEP, Tallahassee*

7:05 p.m. Discussion of Application and air permitting requirements for GRU's proposed new generating unit.

- *A. A. Linero, New Source Review Section, FDEP, Tallahassee.*

7:10 p.m. Discussion of PSD issues and ambient air quality impacts of proposed project.

- *Chris Carlson, Meteorologist FDEP, Tallahassee*

7:15 p.m. FDEP's Draft Best Available Control Technology (BACT) determination for the new plant.

- *A. A. Linero, New Source Review Section, FDEP, Tallahassee*

7:30 p.m. Comments from the public.

9:00 p.m. Adjourn.

DEP AIR PERMITTING SUMMARY SHEET
GRU – COMBINED CYLE UNIT 1
PUBLIC MEETING – ALACHUA COUNTY
JANUARY 12, 2000

GRU proposes to install a new gas-fired Combined Cycle Unit (Unit CC-1) at the J.R. Kelly Generating Station near downtown Gainesville. It will consist of a nominal 83 megawatt (MW) General Electric combustion turbine-electrical generator with an unfired heat recovery steam generator (HRSG). The HRSG will raise sufficient steam to produce approximately another 50 MW via the existing Unit 8 steam turbine-electrical generator. Upon installation of the new proposed unit, the existing Unit 8 boiler will permanently cease operation, though its steam turbine-electrical generator will be retained.

The Florida Department of Environmental Protection (DEP) is the permitting authority for the air construction permit under the provisions of Florida Statutes, the Florida Administrative Code, and our EPA-approved State Implementation Plan per the Code of Federal Regulations.

The DEP received an air permit application and fee on August 9, 1999. The application was updated on December 16 to reflect a cap on emissions of nitrogen oxides. Copies of the application materials were made available to the EPA Region 4 in Atlanta, the U.S. Fish and Wildlife Service Air Quality Branch in Denver, the DEP Northeast District Office in Jacksonville, the DEP Branch Office in Gainesville, and the Alachua County Environmental Protection Department.

The Technical Evaluation and Preliminary Determination and the draft air permit were completed and sent to the applicant along with the Department's Intent to Issue on December 17. Copies were provided to the same agencies as well as to the County Commission.

GRU published the Public Notice of Intent to Issue an Air Construction Permit in The Gainesville Sun December 23. Within the Notice, we advised the venue for this public meeting. We also provided Notice of this public meeting in the Florida Administrative Weekly on December 30.

The Public Notice of Intent provides a 30 day period for anyone to submit comments on the Department's proposed action. It also provided a 14 day period for anyone whose substantial interests were affected by the project to file a petition for an administrative hearing. The period to file a petition ended on January 7 and none was filed.

This meeting will provide the public an opportunity to comment on the proposed permit. Both the application and the Intent to Issue package are still available for public review and copying at the Department's Gainesville, Jacksonville, and Tallahassee offices. We brought with us copies of the key documents in hardcopy versions and on floppy disks in WORD Format. If we run out, we will send copies by mail or e-mail.

The Department will accept comments today and until January 24. In a sense we consider this meeting open until then. We will consider all relevant comments specifically related to air emissions. These public comments as well as those of GRU, Alachua County, EPA and other agencies will be considered in issuing a final permit decision.

Comments may be submitted at this public meeting or sent to:

CONTACT: A. A. Linero, P.E. Administrator
New Source Review Section
Bureau of Air Regulation
2600 Blair Stone Road, MS 5505
Tallahassee, Florida 32399
Tel: (850)921-9523
Internet: alvaro.linero@dep.state.fl.us

Following is a list of contacts within the Department who can assist with questions regarding air permitting and other matters related to the [redacted] Project:

GRU

PUBLIC RECORDS: Kim Tober, Staff Assistant
Bureau of Air Regulation
Tel: (850)921-9533

AIR PERMITTING: Teresa Heron, Engineer
Bureau of Air Regulation, Tallahassee
Tel: (850)921-9529

AIR MODELING: Chris Carlson
Bureau of Air Regulation, Tallahassee
Tel: (850)921-9537

AIR MONITORING: Tammy Eagan
Bureau of Air Monitoring and Mobile Sources
Tel: (850)921-9567

COMPLIANCE: Mort Benjamin
Northeast District Office
Tel: 904/448-4310

LOCAL OFFICE: Pat Reynolds, Manager
NE District/Gainesville Branch Office
Tel: (352)333-2850

LEGAL CONTACT: Doug Beason, Esq.
Office of General Counsel, Tallahassee
Tel: (850)921-9624

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO:

January 6, 2000

al

Re: PSD-FL-276

RECEIVED

JAN 12 2000

BUREAU OF AIR REGULATION

Mr. C. H. Fancy
Chief, Bureau of Air Regulation
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road, MS 48
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Our Air Quality Branch has reviewed the additional information regarding the best available control technology (BACT) analysis for Gainesville Regional Utilities' proposed repowering of its J. R. Kelly Generating Station in Gainesville, Florida. The facility is located 102 km south of Okefenokee Wilderness and 103 km northeast of Chassahowitzka Wilderness, both Class I air quality areas administered by the Fish and Wildlife Service. The Air Quality Branch's technical review comments are enclosed. In summary, Gainesville Regional Utilities' additional information for the BACT analysis is incomplete for reasons detailed in the attached technical review document. As the Air Quality Branch's analysis demonstrates, selective catalytic reduction is economically feasible for this project.

Thank you for giving us the opportunity to comment on this permit application. We appreciate your cooperation in notifying us of proposed projects with the potential to impact the air quality and related resources of our Class I air quality areas. If you have questions, please contact Ms. Ellen Porter of our Air Quality Branch in Denver at (303) 969-2617.

Sincerely yours,

H Dale Hall

for Sam D. Hamilton
Regional Director

Enclosures

cc: M. Kurtz, GRU
EPA
NED
T. Davis
P. Reynolds, NED Branch

Technical Review of
Addition Information for the Best Available Control Technology Analysis
For Gainesville Regional Utilities
J.R. Kelly Generating Station
PSD-FL-276
Gainesville, Florida
by
Air Quality Branch, Fish and Wildlife Service – Denver
December 23, 1999

Gainesville Regional Utilities (GRU) is proposing to re-power its existing #8 steam turbine using a General Electric 7EA simple and combined-cycle gas/oil turbine at its J.R. Kelly Generating Station. The facility is located in Gainesville, Florida, 102 km south of Okefenokee Wilderness and 103 km northeast of Chassahowitzka Wilderness, both Class I air quality areas administered by the U.S. Fish and Wildlife Service. Nitrogen oxides (NO_x) emissions would be controlled by dry low-NO_x (DLN) combustors when firing natural gas (to 9 parts per million - ppm) and water injection (to 42 ppm) when firing oil. The proposed project will result in Prevention of Significant Deterioration (PSD)-significant increases in emissions of NO_X, fine particulate matter less than 10 microns in diameter (PM-10), and carbon monoxide (CO). Emissions (in tons per year – TPY) are summarized below.

POLLUTANT	EMISSIONS INCREASE (TPY)
NO_X	113
PM-10	23
CO	213

In a September 27, 1999, letter and technical review document, we advised the Florida Department of Environmental Protection that we considered GRU's best available control technology (BACT) analysis to be incomplete because it did not properly evaluate the economic and environmental feasibility of selective catalytic reduction (SCR) and SCONOx™ for control of NO_x emissions.

In a submittal dated October 25, 1999, GRU provided a cost analysis for simple cycle operation. During simple cycle operation, we agree that the proposed NO_x limits represent BACT. However, because this facility may operate in a combined cycle mode, it must also be evaluated under those conditions.

On November 10, 1999, the Environmental Protection Agency (EPA) Region IV provided comments recommending SCR as BACT during combined cycle operation. On the same date, GRU submitted responses to our September 27 comments. Following is our review of GRU's responses.

Best Available Control Technology (BACT) Review

SCONOx™

In their November 10 response, GRU again rejected SCONOx™ control technology as being technically infeasible because "the commercial viability of this technology has not been commercially demonstrated for a comparable size CTG [combustion turbine generator]." We continue to believe that SCONOx™ is now technically feasible based on the permit issued to the La Paloma Power Generating Project. As EPA's New Source Review Workshop Manual states, "a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type." However, if GRU selects SCR as BACT, we would not continue to press this issue.

Selective Catalytic Reduction (SCR)

GRU's revised analysis of SCR was well detailed and supported. However, certain information to support costs is still missing and we disagree with some of GRU's conclusions. Our detailed cost analysis is contained in Table 1. In their revised analysis, GRU again dismissed SCR on the premise that it is not economically feasible and because of purported adverse environmental impacts. Following are our detailed comments:

- GRU did not use a true "top-down" approach because the analysis did not start with the lowest achievable emission rate (LAER). As shown in the enclosed Table 2, LAER should not be greater than 2.5 ppm NO_x for a gas turbine; GRU started at 3.5 ppm. To meet 2.5 ppm, NO_x removal efficiency would need to be increased to 72%. Although we did not estimate the increased catalyst cost that would result from this performance boost, we did estimate the increased ammonia use required for the additional NO_x removal. We recommend that GRU re-evaluate BACT based on meeting a 2.5 ppm NO_x limit and obtain a revised quote from Engelhard (the vendor).

- GRU referred to our omission of the cost for ammonia storage in our previous analysis. Our omission was due to the fact that GRU's initial analysis did not contain this cost and we assumed it was for some good reason.

- We continue to question the need for an additional cost for instrumentation, but have included it for the 72% efficient system we analyzed. We did not apply the EPA 10% instrumentation cost factor to the heat recovery steam generator (HRSG) modification cost component as GRU did because we do not believe that there is any relationship between extending the ductwork and additional instrumentation costs. Furthermore, we request documentation to support the $185,000 estimated for the HRSG modification, and also request that this cost reflect only the addition of SCR and not the CO oxidation catalyst which we believe is unnecessary. (CO is simply not a concern from a stationary source, and there is no value in simply hastening its conversion to carbon dioxide.)

- Please clarify whether Florida allows an exemption from sales taxes for pollution control equipment. If so, then the sales tax cost is extraneous.

- We included the stormwater management costs under "site preparation" but request documentation for this cost, especially if the project "footprint" is reduced by elimination of the CO oxidation catalyst.

- We used a different approach in estimating reagent use, relying upon a "rule of thumb" that it takes 0.6 tons of ammonia to react with one ton of NO_x. This allows for inefficiencies in the reaction and tends to overestimate reagent cost. Our reagent cost is also greater due to the increased NO_x removal.

- We provided a more rigorous analysis of catalyst replacement and disposal costs, but continue to differ with GRU regarding the appropriate Capital Recovery Factor. We continue to believe that the interest rate used to calculate the Capital Recovery Factor should be the 7% value recommended by the EPA OAQPS Control Cost Manual and EPA Region IV in previous correspondence.

- Electricity consumption for ammonia vaporization is greater than GRU's estimate due to the increased NO_x removal.

- The Heat Rate Penalty may be less than the 0.5% recommended by EPA and used by GRU due to the lower (1.5") pressure drop stated by Engelhard. In fact, if the "0.15% penalty per inch of pressure drop" estimate of the Gas Turbine Work Group of the ICCR is used, the Heat Rate Penalty is reduced to 0.225%. The "computational error" mentioned by GRU resulted from our having to guess at the electricity rate used by GRU in its first analysis; such "errors" can be minimized when the applicant provides a clear description of its methods.

- We corrected the Overhead costs and appreciate GRU's catching this error. We are not aware of any computational error in our calculation of Direct Cost; this is probably simply due to a difference in approach.

When we re-calculated the economics of SCR for this application based on the preceding discussion, we estimated a cost of well under $4,000 per ton of NO_x removed. (See enclosed tables.) This essentially confirms our belief that this project would not be subject to any extraordinary costs that would make SCR economically infeasible.

GRU has attempted to equate the reduction in NO_x in ppm to the ammonia slip rate in ppm. Due to the different molecular weights of those two compounds, a comparison of the actual weights of those compounds (Table 1.e.) shows that, while 150 tons of NO_x would be reduced per year, annual ammonia emissions would not exceed 29 tons. If GRU is concerned about the particulate emissions that would result from oil firing, it should consider reducing its proposed use of oil from 1000 hours per year. While we applaud GRU's retirement of Unit #8 and the resulting reduction in emissions, it is still their responsibility to minimize emissions from the new unit.

Environmental impacts have not been shown to be unique or extraordinary. Applicants who propose SCR typically state that the types of "problems" cited by GRU can be prevented by good operation and maintenance practices.

Conclusions and Recommendations

- GRU's BACT analysis is incomplete because it improperly dismissed SCONOx™. However, we are willing to waive that demonstration if SCR is elected.
- GRU's BACT analysis does not demonstrate that the cost of installing and operating SCR would be excessive when compared to other similar proposals. The only "unusual" cost that might be experienced by GRU is related to revisions of the stormwater management system.
- We continue to believe that SCR represents BACT for this application, as demonstrated by our analysis.

Contact: Ellen Porter, Air Quality Branch (303) 969-2617.

Kelly Generating Station
Table 1.a
Plant Data

				Capacity	
Site	FWS Area(s)	Source		(mmBtu/hr)	(MW)
Kelly Station, Gainesville, GA	OKEF	1	CCT	1083	83+40
				each	each

Given/Assumptions

Source	CCT
Exhaust gas flow (lb/Hr)	2,350,008
Exhaust gas flow (acfm)	887,436
Basic Equipment Costs	$710,000
Ammonia storage cost	$50,000
Sales Tax	6%
HSRG Modification	$185,000
Uncontrolled Emission rate (gas--lb/hr)	32.0
Uncontrolled Emission rate (oil--lb/hr)	166.0
Uncontrolled Emission rate (TPY)	208
Control efficiency (%)	72%
Operating Hours per Year (gas)	7,760
Operating Hours per Year (oil)	1,000
Operating Hours per Shift	8
Operating Shifts per Year	1095
Operating Labor Cost ($/hr)	$28.40
Maintenance Labor Cost ($/hr)	$30.61
Electrical Cost ($/kWh)	$0.03
Reagent Use (lb NH3/lb NOx)	0.6
Reagent Costs ($/T)	$102
NH3 Pump& Dilution Air Blower Power (kW)	5
Power to Vaporize NH3 (kW/lb NH3 an)	2
Catalyst replacement	$350,000
Catalyst replacement labor	$40,000
Catalyst disposal ($/T)	$500
Catalyst weight (T)	50.8
Catalyst life (Yr)	5
Heat rate penalty (% of MW output)	0.5%
Ammonia slip (ppm)	5
Equipment Life (Yr)	15
Interest Rate (%)	7.00%

Kelly Generating Station

Table 1.b

Capital Costs (OAQPS Control Cost Manual Chapter 3--Catalytic Incinerators)

Cost Item		Factor	Cost
Direct Costs			CCT
Purchased equipment costs			
SCR + auxiliary equipment			$710,000
Ammonia storage			$50,000
Subtotal = A'			$760,000
Instrumentation		0.10 A'	$76,000
HSRG Modification			$185,000
Total = A			$1,021,000
Sales taxes		0.06 A	$61,260
Freight		0.05 A	$51,050
Purchased equipment cost, PEC	B=	1.21 A	$1,133,310
Direct installation costs			
Foundations & supports		0.08 B	$90,665
Handling & erection		0.14 B	$158,663
Electrical		0.04 B	$45,332
Piping		0.02 B	$22,666
Insulation		0.01 B	$11,333
Painting		0.01 B	$11,333
Direct installation costs		0.30 B	$339,993
Site preparation	As required, SP		$100,000
Buildings	As required, Bldg.		$0
Total Direct Costs, DC		1.30 B+SP+Bldg	$1,573,303
Indirect Costs (installation)			
Engineering		0.10 B	$113,331
Construction and field expenses		0.05 B	$56,666
Contractor fees		0.10 B	$113,331
Start-up		0.02 B	$22,666
Performance test		0.01 B	$11,333
Contingencies		0.03 B	$33,999
Total Indirect Cost, IC		0.31 B	$351,326
Total Capital Investment = DC + IC		1.61 B+SP+Bldg	$1,924,629

Kelly Generating Station
Table 1.c
Annual Costs (OAQPS Control Cost Manual Chapter 3--Catalytic Incinerators)

Cost Item	Factor				Cost
Direct Annual Costs, DC					CCT
Operating labor					
Operator	0.5 hr/shift				$15,549
Supervisor	15% of operator				$2,332
Operating materials					
Reagent					
0.6 T NH_3/T NO_x	208 TPY NO_x/0.28 Aqueous NH_3*				
		0.72 % control =	321 TPY		
		321 TPY *	102 $/T =		$32,755
Maintenance					
Labor	0.5 hr/shift				$16,759
Material	100% of maintenance labor				$16,759
Catalyst replacement	$350,000 +	6% tax + 5% freight =		$389,550	
labor				40,000.00	
disposal	500 $/T *	50.8 T =		$25,400	
		Total =		$454,950	
	$454,950 * CRF @		0.2439 =		$110,958
Electricity					
NH_3 Pump& Dilution Air Blower Power					
5 kW*	0.03 $/kWh*		8,760 hr/yr=		$1,314
Vaporization of aqueous NH_3					
2 kW/lbNH3an*0.28lb/NH3/lbNH3*		73.3 lb NH_3/hr*			
	0.03 $/kWh*		8,760 hr/yr=		$10,790
Total DC					$207,217
Energy Costs					
Heat rate penalty	83 MW *	8,760 hr/yr *			
	1000 kW/MW *	0.005 loss *	0.03 $/kWh =		$109,062
Indirect Annual Costs, IC					
Overhead	60% of maintenance costs				$30,840
Administrative charges	2% of Total Capital Investment				$38,493
Property tax	1% of Total Capital Investment				$19,246
Insurance	1% of Total Capital Investment				$19,246
Capital recovery	0.1098 * [Total Capital Investment-(1+		0.11)(Cat Cost)]		$197,791
Total IC					$305,616
Total Annual Cost	DC + IC				$621,895

Kelly Generating Station
Table 1.d
Cost Effectiveness

Source	CCT	Units
Pollutant	NOx	
Uncontrolled emissions	208	TPY
Control efficiency	72%	
Controlled emissions	58	TPY
Pollutants removed	150	TPY
Annual cost	$621,895	/yr
Annual cost - Emission fees saved	$617,399	@ $30/T
Cost/ton	$4,150	/T

Kelly Generating Station
Table 1.e
Environmental Impacts of SCR at 72% removal

NOx removed	150 TPY		
Ammonia released	29 TPY @	5 ppmv	

5 ppmvd NOx* E-06 * (20.9/(20.9- 15 % O2)) * 17 MW NH3 * 8740 dscf/mmBtu (fuel input) F-factor(gas)/ 385 scf/lb-mole (vol/mol ratio) = 0.007 lbm/mmBtu

Table 2.a Combined Cycle Gas Turbine Limits from RBLC

Facility Name	Project Description: Simple Cycle	Combined Cycle	Peak Base	Turbine Type	Duct Burner	Power: MW Each	MW Total	mmBtu/hr	HP	Permit #	Permit Issue Date	NOx Emission Limits: Dry Lox-NOx Comb. Gas (ppm)	Dry Lox-NOx Comb. Oil (ppm)	SCR Gas (ppm)	SCR Oil (ppm)
Alabama Power Company		Y			Y	100	100	353	10566	AL-0115	Dec-97	15.0			
Alabama Pwr--Theodore		Y			Y	170	170			AL-0128	Mar-99	Y		3.5	
American Cogen Tech.											Sep-85			17.0	
Anitec Cogen Plant		Y						451		NY-0061	Jul-93	25.0			
Arrowhead Cogen											Dec-89			9.0	
Baf Energy											Jul-87			9.0	
Bear Island Paper		Y			Y	139	139	474	14172	VA-0190	Oct-92			9.0	15.0
Bear Mountain Limited		Y				48	48			CA-0858	Aug-94			3.6	
Berkshire, MA		Y			N	2*178	272			MA-0022	Sep-97			3.5	9.0
Bermuda Hundred		Y			Y			1175		VA-0184	Mar-92			9.0	15.0
Blue Mtn. Pwr.		Y			Y	153	153	541	16166	PA-0148	Jul-96	Y	Y	4.0	8.4
BMW Manufacturing Corp		Y						55							
Bridgeport Energy, LLC		Y				260	520			CT-0130	Jun-98			6.0	25.0
Brooklyn Navy Yard Cogen		Y				240	240	848	25358	NY-0044	Jun-95			3.5	10.0
Brush Cogen		Y			Y			350		CO-0018	May-94	25.0			
Carson Energy Group & Central		Y		2 GE LM6000				450		CA-0812	Jul-93			5.0	
Casco Ray Energy Co		Y				170	340			ME-0020	Jul-98			3.5	
Champion Int. & Champ. Clean Energy		Y				175	175			ME-0019	Sep-98	9.0	42.0		
Cogen Technologies											Jun-87			9.6	
Colorado Power Partnership		Y			Y			385 ea.		CO-0019	May-92	42.0			
Crockett Cogen. - C&H Sugar		Y		GE PG7221 (FA)	Y	240	240			CA-0855	Oct-93			5.0	
Dighton Power Associate, LP		Y				110	175	1327		MA-0023	Oct-97	Y	Y	Y	Y
Doswell Ltd											May-90			9.0	
Ecoelectrica		Y				461	461	1629	48709	PR-0004	Oct-96			7.0	9.0
Fleetwood Cogeneration					Y	105	105	360	10764	PA-0099	Apr-94			15.0	
Formosa Plastics		Y				132	132	450	13455	PSD-LA-560	Mar-97	9.0			
Formosa Plastics		Y				132	132	450	13455	PSD-LA-560	Mar-95	9.0			
General Electric Plastics		Y			Y			1200		207-0008-X016	May-98				
Gordonsville Energy					Y	445	445	1520	45433	VA-0189	Sep-92			9.0	
Granite Road Limited						135	135 .	461	13781	CA-0441	May-92			3.5	
Grays Ferry		Y			Y	337	337	1150	34384	PA-0098	Nov-92	9.0			
Hermiston Generating		Y				497	497	1696	50709	OR-0011	Apr-94			4.5	
Hoffman-LA Roche - Nutley Cogen Facility		Y		GE LM500	Y			87			May-95				
Indeck Energy Co.		Y		GE Frame 6	Y			591		563203 0099	May-93	32.0	54.0		
Indeck Oswego Energy Center		Y		GE Frame 6	Y			563		351200 0211 0000	Oct-94	42.0	65.0		
Indeck Yerkes Energy Services		Y		GE Frame 6	Y			452		142400 0133	Jun-92	42.0	65.0		
International Paper		Y						338		PSD-LA-93(M-3)	Feb-94	25.0			
Kamine/Besicorp						190	190	650	19434	2320-00018/0000	Nov-92	9.0		9.0	
Kamine/Besicorp						191	191	653	19524	8-4638-00022/01-0	Nov-92	9.0		9.0	
Kingsburg Energy					Y	35	35	122	3645	CA-0347	Sep-89			6.0	
Lakewood Cogeneration						56	56	190	5681	NJ-0013	Apr-91			9.0	
Las Vegas Cogen											Oct-90			10.0	
Linden Cogeneration		Y				165	165	583	17434	NJ-0011	Aug-91				
Lsp-Cottage Grove						577	577	1970	58901	MN-0022	Mar-95			4.5	
Maui Electric Co. Ltd.		Y	Peak		N	28	28			HI-0013	Dec-91	42.0			
Maui Electric Co. Ltd.		Y	Peak		N	28	28			HI-0015	Jul-92	42.0			
Meak Coated Boards, Inc		Y			N			568		AL-0096	Mar-97	25.0	42.0		

Table 2.a Combined Cycle Gas Turbine Limits from RBLC

	Project Description					Power					Permit	NOx Emission Limits			
						MW					Issue	Dry Lox-NOx Comb.		SCR	
Facility Name	Simple Cycle	Combined Cycle	Peak Base	Turbine Type	Duct Burner	Each	Total	mmBtu/hr	HP	Permit #	Date	Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
Megan-Racine Associates, Inc.		Y								NY-0057	Aug-89	42.0	65.0		
Mid-Ga. Cogen						116	116	410	12257	GA-0063	Apr-96			9.0	20.0
Narragansett Electric					Y	398	398	1360	40663	RI-0010	Jun-98			9.0	
Nevada Cogen Associates #1		Y		GE LM-2500 (3)	N	3*85	255			NV-0020	Jan-91				
Nevada Cogen Associates #2		Y		GE LM-2500 (3)	N	3*85	255			NV-0018	Jan-91				
Newark Bay Cogen						171	171	585	17491	NJ-0009	Nov-90			8.3	
Newark Bay Cogen						181	181	617	18448	NJ-0017	Jun-93			8.3	16.0
Northern Consolidated Power		Y			Y					PA-0083	May-91	25.0			
Ocean State Power											Dec-88			9.0	
Ols Energy											Jan-88			9.0	
Panda-Kathleen		Y				75	75	265	7925	FL-0102	Jun-95	15.0			
Pasny/Holtsville		Y				336	336	1146	34264	NY-0047	Sep-92	9.0			
Pawtucket Power											Jan-89			9.0	
Pedricktown Cogen						293	293	1000	29899	NJ-0010	Feb-90			9.0	
Pilgrim Energy Center					Y	410	410	1400	41859	NY-0075	Apr-95			4.5	
Portland General Elec						504	504	1720	51427	OR-0010	May-94			4.5	
PSI Energy Inc Wabash River Station		Y				192+110	302	1775		IN-0053	May-93				
Richmond Power Enterprise											Dec-89			8.2	
Sacramento Cogen Authority P&G	Y	Y		GE LM6000	N			1263		CA-0810	Aug-94				
Sacramento Power Authority Campbell soup		Y		Siemens V84.2	N			1257		CA-0811	Aug-94				
Sacramento Power Authority Campbell soup		Y		Siemens V84.2	N			1257		CA-0845	Aug-94			3.0	
Saguaro Power Company						35	35	122	3645	NV-0015	Jun-91			9.0	
Santa Rosa Energy LLC		Y		GE 7FA	Y	241	241	585		FL-0116	Dec-98	9.0	9.8		
Saranac Energy Company					Y	329	329	1123	33577	NY-0046	Jul-92			9.0	
Selkirk Cogen					Y	344	344	1173	35072	NY-0045	Jun-92			9.0	
Seminole Fertilizer											Mar-91			9.0	
Seminole Fertilizer Corp						26	26	92	2747	FL-0059	Mar-91			9.0	
Seminole Hardee Unit 3		Y				2*244	488	981	29331	FL-0104	Jan-96	15.0		12.0	
Sepco		Y		GE Model 7	N			920		CA-0813	Oct-94				
Sithe/Independence		Y				625	625	2133	63775		Nov-92			4.5	
South Mississippi Electric Power Association		Y			N			1299		MS-0028	Apr-96				
Sumas Energy											Jun-91			6.0	
Sumas Energy											Dec-90			9.0	
Sumas Energy Inc						88	88	311	9298	WA-0027	Dec-92			6.0	
Sunlaw Cogen		Y		GE LM2500-M-2	N	28	28			CA-0863	Jan-94	2.0		9.0	
SW PSCo						100	100	353	10566	NM-0028	Nov-96	15.0			
SW PSCo						100	100	353	10566	NM-0029	Feb-97	?			
Talahassee		Y				260	260					12.0	42.0		
Tempo Plastics		Y			N					CA-0793	Jan-97	31.0			
Tenaska WA Partners		Y			Y	1	1	2	55	WA-0275	May-92			7.0	
Thermo Industries LTD		Y			Y			246		CO-0017	Feb-92	25.0			
Tiger Bay						473	473	1615	48281	FL-0072	May-92	15.0			
TNP Techn, LLC		Y		GE LM6000	Y			750		NM-0039	Aug-98			15.0	
Union Carbide Corp		Y			N	256	256	2023		LA-0096	Sep-95	25.0			
Union Oil											Mar-86			2.5	
University of Medicine & Dentistry of New Jersey		Y			N			168		NJ-0031	Jun-97				
Unocal						0	0			CA-0613	Jul-89			9.0	
Westbrook Power LLC		Y		GE	N	2*264	528			ME-0018	Dec-98			2.5	
Western Power Sys.											Mar-88			9.0	
Willamette Ind.											Apr-85			15.0	
Wyandotte Energy		Y			N	500	500			MI-0244	Feb-99			4.5	

Table 2.b CCT Permits Pending or Not Yet in RBLC

Facility Name/Location	Project Description					Power					Permit Issue Date	NOx Emission Limits			
												Dry Lox-NOx Comb.		SCR	
	Simple Cycle	Combined Cycle	Peak Base	Turbine Type	Duct Burner	MW Each	MW Total	mmBtu/hr	HP	Permit #		Gas (ppm)	Oil (ppm)	Gas (ppm)	Oil (ppm)
AES--Red Oak		Y		GE 7241 (FA)		3*186	558	3 x 1748		NJ					
AES--Red Oak		Y		Siemens Westinghouse 501F	N	4*192	768			NJ				3.5	
Alabama Pwr-Theodore Co-Gen		Y			Y									3.5	
American Electric Co-op		Y		**Siemens V84.3A**	Y	**268**	**268**							**4.5 / 3**	
Androscoggin Energy		Y			Y	3*50	150	3 x 619		ME				6.0	42 0
ARCO Watson Project						45	45			CA	Oct-97			5.0	
Bridgeport Energy Project														**6.0**	
Calpine--South Point		Y			Y	500	500			AZ		Y		3.0	
Cogen Tech. Linden Venture		Y				**581**	**581**	**1983**	**59275**	**NJ**				**3.5**	
Desert Basin Gen		Y						2 x 1940		AZ				4.5	
Dighton, MA										**MA**				3.5	
Duke Energy--New Smyrna		Y		GE PG7241FA		2*165	330			FL		12.0			
Enron (LAER)										CA				2.5	
FPC--Hines		Y		W 501Frame		2*165	330			FL				6 0	
FPC--Polk		Y				**2*235**	**470**			**FL**					
Frontera Power		Y				330	330			TX		15.0			
Griffith Energy		Y			Y	650	650			AZ				3 0	
HDPP (LAER)										CA				3 0	
Hermiston Generating		Y								CA	Dec-95			4.5	
High Desert Power		Y								CA		9 0		2.5	
Kelly Generating Station															
Kissimmee Utility--Cane Is. #3		Y		GE Frame 7A	Y	167	167			FL		12 0	42 0	6.0	15 0
Lakeland McIntosh CCT		Y				350	350			FL				7.5	15 0
Lake Worth Gen.		Y		GE Frame 7FA		170	170			FL		9 0		-	
Liberty Electric		Y		GE Frame 7A		2*180	500			PA				3.5	
LaPoloma Generating		Y				4*262	1048			CA				3.0	
Mississippi Pwr--Daniels		Y				170	170			MI		Y		3.5	
Northwest Regional Power		Y		GE Frame 7FA		4*210	840	1530	45746	WA		9.0			
Osceola Pwr			Peak	GE PG7241 (FA)		3*170	510			FL		10 5	42 0		
Orange Generation--Bartow		Y				2*41	82			FL		15 0			
PSCoNM-Afton		Y		GE Frame 7		140	215	1470		NM		9 0	42.0		
Rotterdam, N.Y.										NY				4 5	
Sacramento Power						115	115'			CA	Dec-94			3.0	
Sumas		Y				2*350	700			WA		9.0		4 5	
Sutter						170	170					Y		3 5	
TX-NM Pwr--Lordsburg		Y		aero		2*40	80			NM		15 0	25.0		
Three Mountain Power		Y				500	500			CA				2.5	
Tiverton, RI										RI				3.5	

GRU

GAINESVILLE REGIONAL UTILITIES

RECEIVED

JAN 04 2000

BUREAU OF AIR REGULATION

January 4, 2000

Mr. Clair Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

RE: DEP File No. 0010005-002-AC (PSD-FL-276)
Gainesville Regional Utilities
J.R. Kelly Generating Station - Combined Cycle Project

Dear Mr. Fancy:

Enclosed is a notarized proof of publication of the Public Notice of Intent to Issue Air Construction Permit for the above-referenced project.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: D. Beck
D. DuBose
T. Heron, FDEP-Tall
M. Kurtz
A. Linero, FDEP-Tall
S. Manasco
G. Swanson
K. Tober, FDEP-Tall.
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NO. 17774

THE GAINESVILLE SUN
STATE OF FLORIDA
SUNDAY
COUNTY OF ALACHUA

PUBLISHED DAILY AND
GAINESVILLE, FLORIDA

Before the undersigned authority personally appeared Naomi Williams-Jordan

Who on oath says that he/she is Classified Assistant Manager of THE GAINESVILLE SUN,

a daily newspaper published at Gainesville in Alachua County, Florida, that the attached copy of

advertisement, being a Public Notice of Intent

in the matter of ....

in the ....Court, was published in said newspaper in the issue of,.

December 23, 1999

Affiant further says that the said THE GAINESVILLE SUN is a newspaper published at Gainesville, in said Alachua County, Florida, and that the said newspaper has heretofore been continuously published in said Alachua County, each day, and has been entered as second class mail matter at the post office in Gainesville, in said Alachua County, Florida, for a period of one year next preceding in the first publication of the attached copy of advertisement; and affiant further says that he has neither paid nor promised any person, firm or corporation any discount for publication in the said newspaper.

Sworn to and subscribed before me this

23 day of Dec. A.D., 1999

Naomi Williams-Jordan

Sharon K. Williams
(Seal) Notary Public

SHARON K. WILLIAMS
MY COMMISSION # CC 814219
EXPIRES: March 3, 2003
Bonded Thru Notary Public Underwriters

12/30/99

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Volume 25, Number 52, December 30, 1999
Notices of Meetings, Workshops and Public Hearings

...previous

Department of Environmental Regulation

The **Department of Environmental Protection** announces a public meeting to which all persons are invited:

DATE AND TIME: January 12, 2000, 7:00 p.m. – 9:00 p.m.

PLACE: Gainesville Regional Utilities Administration Building, Multi-purpose Room, 301 Southeast 4th Avenue, Gainesville, Florida

PURPOSE: To accept public comments and provide status of Department's Intent to Issue an Air Construction Permit to construct a combined cycle combustion turbine-electrical generator at the: Gainesville Regional Utilities, J. R. Kelly Generating Station, 605 Southeast 3rd Street, Gainesville, Alachua County, Florida.

The permitting action is subject to the Department's rules for the Prevention of Significant Deterioration of Air Quality and Best Available Control Technology (BACT).

A copy of the agenda and the Department's proposed permit and supporting documents can be obtained by contacting: Ms. Teresa Heron, Department of Environmental Protection, 2600 Blair Stone Road, MS 5505, Tallahassee, Florida 32399, Telephone (850)921-9529, or by phoning the Bureau of Air Regulation's New Source Review Section, (850)921-9533.

Pursuant to the provisions of the Americans with Disabilities Act, any person requiring special accommodations to participate in this meeting is asked to advise the agency at least 48 hours before the meeting by contacting the Personnel Service Specialist, Bureau of Personnel, (850)488-2996. If you are hearing or speech impaired, please contact the agency by calling 1(800)955-8771 (TDD).

Department of Juvenile Justice

The **Department of Juvenile Justice** announces a meeting of The Juvenile Justice Standards and Training Commission to which any interested parties are invited.

DATES AND TIMES: January 12, 2000, 1:00 p.m. – 4:30 p.m.; January 13, 2000, 9:00 a.m. – 4:30 p.m.

PLACE: Radisson Hotel, 415 North Monroe Street, Tallahassee, Florida 32301, Telephone (850)224 6000

PURPOSE: Regular meeting to discuss issues related to staff training for Juvenile justice programs, as well as future plans for the juvenile Justice training system.

A copy of the agenda may be obtained after December 31, 1999 by contacting: Peggy Sanders, Florida Department of Juvenile Justice, Office of Staff Development, 2737 Centerview Drive, Suite 114, Tallahassee, Florida 32399-3100, Telephone (850)488-8825.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

RECEIVED
JAN 03 2000
BUREAU OF AIR REGULATION

DEC 29 1999

4APT-ARB

A. A. Linero, P.E.
Administrator
New Source Review Section
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

SUBJECT: Custom Fuel Monitoring Schedule Proposed for Gainesville Regional Utility (GRU) - J. R. Kelly Generating Station located in Alachua County, Florida

Dear Mr. Linero:

This letter is in response to your December 20, 1999, request for approval of a custom fuel monitoring schedule for GRU-Kelly. GRU-Kelly will operate one combined cycle combustion turbine subject to 40 C.F.R. Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines. As requested, Specific Conditions 25, 39, 40, 42 and 43 have been reviewed. Additionally, Specific Condition 37 was reviewed Region 4 has concluded that the use of acid rain nitrogen oxides (NO_X) continuous emission monitoring system (CEMS) for demonstrating compliance, as described in Specific Conditions 25 and 39, is acceptable. The U.S. Environmental Protection Agency (EPA) Region 4 has also concluded that the natural gas custom fuel monitoring schedule proposed in Specific Condition 42 and the fuel oil monitoring schedule described in Specific Condition 43 are both acceptable.

According to 40 C.F.R. 60.334(b)(2), owners and operators of stationary gas turbines subject to Subpart GG are required to monitor fuel nitrogen and sulfur content on a daily basis if a company does not have intermediate bulk storage for its fuel. 40 C.F.R. 60.334(b)(2) also contains provisions allowing owners and operators of turbines that do not have intermediate bulk storage for their fuel to request approval of custom fuel monitoring schedules that require less frequent monitoring of fuel nitrogen and sulfur content.

Region 4 reviewed Specific Condition 42 which allows SO_2 emissions to be quantified using procedures in 40 C.F.R. 75 Appendix D in lieu of daily sampling as required by 40 C.F.R. 60.334(b). Since the specific limitations listed in the permit condition are consistent with previous determinations, we have concluded that the use of this custom fuel monitoring schedule is acceptable.

Specific Conditions 39 and 40 involve the method used to monitor NO_X excess emissions and Specific Condition 25 describes the use of CEMS for demonstrating continuous compliance with the NO_x emission limit. Under the provisions for 40 C.F.R. 60.334(c)(1), the operating parameters used to identify NO_X excess emissions for Subpart GG turbines are water-to-fuel injection rates and fuel nitrogen content. As an alternative to monitoring NO_X excess emissions using these parameters, GRU-Kelly is proposing to use a NO_X CEMS that is certified for measuring NO_X emissions under 40 C.F.R. Part 75. Based upon a determination issued by EPA on March 12, 1993, NO_X CEMS can be used to monitor excess emissions from Subpart GG turbines if a number of conditions specified in the determination are met and included in the permit condition. Additionally, the use of a NO_x CEMS for demonstrating continuous compliance on a 30-day rolling average when firing natural gas and a 3-hour rolling average when firing fuel oil is acceptable.

Specific Condition 37 addresses the potential for correcting results to ISO standard day conditions. The basis for this requirement is that, under the provisions of 40 C.F.R. 60.335(c), NO_x results from performance tests must be converted to ISO standard day conditions. As an alternative to continuously correcting results to ISO standard day conditions, GRU-Kelly plans to keep records of the data needed to make this conversion, so that NO_x results could be calculated on an ISO standard day condition basis anytime at the request of EPA or the Florida DEP. This approach is acceptable, since the construction permit contains NO_x limits that are more stringent than those in Subpart GG, and compliance with Subpart GG for these units would be a concern only in cases when a turbine is in violation of the NO_x limits in its permit.

Finally, Specific Condition 43 addresses the monitoring schedule for fuel oil. According to 40 C.F.R. 60.334(b)(1), the nitrogen and sulfur content of the fuel oil must be monitored each time a new shipment of fuel oil is transferred to bulk storage. GRU-Kelly is proposing to use the fuel analysis provided by the fuel vendor instead of sampling each shipment directly. Provided that all the oil received at the plant complies with the applicable sulfur content limit of 0.8 weight percent, this approach is acceptable, since the specific condition states that the fuel vendor's analyses will comply with the test method requirements of 40 C.F.R. 60.335(d).

If you have any questions about the determination provided in this letter, please contact Ms. Katy R. Forney of my staff at 404-562-9130.

Sincerely yours,

for Gregg M. Worley

R. Douglas Neeley
Chief
Air and Radiation Technology Branch
Air, Pesticides and Toxics
Management Division

cc: J. Heron, BAR
M. Kurtz, GRU
NPS
NED
T. Davis ECT

December 27, 1999

RECEIVED
DEC 29 1999
BUREAU OF AIR REGULATION

Mr. Clair Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

RE: DEP File No. 0010005-002-AC (PSD-FL-276)
Gainesville Regional Utilities
J.R. Kelly Generating Station - Combined Cycle Project

Dear Mr. Fancy:

Enclosed is a proof of publication of the Public Notice of Intent to Issue Air Construction Permit for the above-referenced project.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: D. Beck
D. DuBose
C. Heidt
T. Heron, FDEP-Tall
R. Klemans
M. Kurtz
A. Linero, FDEP-Tall
S. Manasco
G. Swanson
K. Tober, FDEP-Tall.
JRK CC1

JRKCC1proofofpub1299.y33

Legal Notice

PUBLIC NOTICE OF INTENT TO ISSUE AIR CONSTRUCTION PERMIT
STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
DEP File No. 0010005-002-AC (PSD-FL-276)

Gainesville Regional Utilities
J R Kelly Generating Station
Alachua County

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit under the requirements for the Prevention of Significant Deterioration (PSD) of Air Quality to Gainesville Regional Utilities. The permit is to construct a nominal 83 megawatt (MW) natural gas and distillate fuel oil-fired combustion turbine generator at the existing J.R. Kelly Generating Station in downtown Gainesville, Alachua County. A Best Available Control Technology (BACT) determination was required for particulate matter (PM10) and carbon monoxide (CO) pursuant to Rule 62-212.400, F.A.C. The applicant's name and address are Gainesville Regional Utilities (GRU), Post Office Box 147117, Gainesville, Florida 32614-7117.

The proposed unit (Combined Cycle Unit CC-1) is a General Electric PG7121EA combustion turbine-electrical generator with an unfired heat recovery steam generator that will raise sufficient steam to produce approximately another (maximum) 50MW via the existing Unit 8 steam-driven electrical generator. Upon installation of the new proposed unit, the Unit 8 steam boiler will permanently cease operation. Distillate oil will be used as back up fuel and limited to a 1000 hours per year. The turbine will be able to operate in simple cycle (i.e. without HRSG or steam-electrical turbine). The project also includes: a 78 foot stack for simple cycle operation; a 100 foot stack for combined cycle operation, and a cooling tower (existing).

Emission of PM10 and CO will be controlled by good combustion of clean pipeline supplied natural gas or maximum 0.05 percent sulfur distillate fuel oil. The BACT determination for CO is 20 parts per million by volume (ppmvd). Typical expected CO emissions are 5-10 ppmvd. The BACT determination for PM10 is 5 pounds per hour (lb/hr) while burning natural gas and 10 lb/hr while burning fuel oil with a visible emission limitation of 10 percent opacity. Nitrogen oxides (NOx) emissions will be controlled by Dry Low NOx technology capable of achieving 9 parts per million by volume (ppmvd) at 15 percent oxygen while firing natural gas and by wet injection achieving 42 ppmvd @ 15% O2 when burning fuel oil. Sulfuric acid mist (SAM), sulfur dioxide (SO2), and volatile organic compounds (VOC) will be controlled by good combustion of inherently clean fuels.

PSD and BACT do not apply for NOx, SO2, SAM, PM and VOC emissions. The maximum future potential (i.e., permitted allowable) annual emissions in tons per year are summarized below for comparison with recent past actual annual emissions from Unit 8 which is slated for retirement. The increases shown are based on future potential emissions minus past actual emissions.

Pollutant	Unit 8 (present potential)	Unit 8 (past actual)	CC-1 (future potential)	Increase	PSD Significance
PM	296	1.8	24.4	22.6	25
PM10	296	1.8	24.4	22.6	15
SAM	150	1.2	5.4	4.1	7
SO2	6,498	29	47.1	18	40
NOx	1050	94	133 (cap)	39	40
VOC	12	2	9.2	7	40
CO	78	18	231 (yr 1)	213 (yr 1)	100
CO	78	18	189 (yr 2+)	189 (yr 2+)	100

The modest maximum increases in actual emissions and the very substantial reduction in total potential emissions will accompany a tripling of generation capacity compared with the existing Unit 8 and as much as a six-fold increase in actual power generation. The Department and GRU agreed to an emission cap for Unit CC-1 such that the total NOx increase will be less than 40 TPY and thus exempt from PSD for that pollutant.

An air quality impact analysis was conducted. Maximum predicted impacts due to proposed emissions from the project are less than the applicable PSD Class I and Class II significant impact levels.

The Department will issue the FINAL Permit, in accordance with the conditions of the DRAFT Permit, unless a response received in accordance with the following procedures results in a different decision or significant change of terms or conditions.

The Department will accept written comments concerning the proposed permit issuance action for a period of 30 (thirty) days from the date of publication of this Public Notice of Intent to Issue Air

Legal Notice

Construction Permit. Written comments should be provided to the Department's Bureau of Air Regulation at 2600 Blair Stone Road, Mail Station #5505, Tallahassee, FL 32399-2400. Any written comments filed shall be made available for public inspection. If written comments received result in a significant change in the proposed agency action, the Department shall revise the proposed permit and require, if applicable, another Public Notice. The Department will hold a public meeting to explain the proposed permitting action and receive public comments. The meeting will be held from 7 to 9 p.m. on January 12, 2000 at the GRU Administration Building, Multi-purpose Room, 301 Southeast 4th Avenue in Gainesville.

The Department will issue the permit with the attached conditions unless a timely petition for an administrative hearing is filed pursuant to sections 120.569 and 120.57 F.S., before the deadline for filing a petition. The procedures for petitioning for a hearing are set forth below. Mediation is not available in this proceeding.

A person whose substantial interests are affected by the proposed permitting decision may petition for an administrative proceeding (hearing) under sections 120.569 and 120.57 of the Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station #35, Tallahassee, Florida 32399-3000. Petitions filed by the permit applicant or any of the parties listed below must be filed within notice under section 120.60(3) of the Florida Statutes must be filed within fourteen days of publication of the public notice or within fourteen days of receipt of this notice of intent, whichever occurs first. Under section 120.60(3), however, any person who asked the Department for notice of agency action may file a petition within fourteen days of receipt of that notice, regardless of the date of publication. A petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 F.S., or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the approval of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205 of the Florida Administrative Code.

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

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

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Dept. of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Telephone: 850/488-0114
Fax: 850/922-6979

Dept. of Environmental Protection
Northeast District Office
7825 Baymeadows Way, Suite 200B
Jacksonville, Florida
904/448-4300
Fax: 904/448-4363

Dept. of Environmental Protection
Northeast District Branch
101 NW 75 Street, Suite 3
Gainesville, Florida 32607
Telephone: 352/333-2850
Fax: 352/333-2856

The complete project file includes the Draft Permit, the application, and the information submitted by the responsible official, exclusive of confidential records under Section 403.111, F.S. Interested persons may contact the New Resource Review Section at 111 South Magnolia Drive, Suite 4, Tallahassee, Florida 32301, or call 850/488-0114, for additional information.

DEP ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION)

1. Kim Jober
2. MS 5500
3. ______
4. ______
5. ______

PLEASE PREPARE REPLY FOR:

____ SECRETARY'S SIGNATURE

____ DIV/DIST DIR SIGNATURE

____ MY SIGNATURE

____ YOUR SIGNATURE

____ DUE DATE ______

ACTION/DISPOSITION

____ DISCUSS WITH ME

____ COMMENTS/ADVISE

____ REVIEW AND RETURN

____ SET UP MEETING

____ FOR YOUR INFORMATION

____ HANDLE APPROPRIATELY

____ INITIAL AND FORWARD

____ SHARE WITH STAFF

____ FOR YOUR FILES

COMMENTS:

FROM: ______ DATE: ______ PHONE: ______

DEP 15-026 (12/93)

NOTICE OF PUBLIC MEETING

The Department of Environmental Protection announces a public meeting to which all persons are invited:

DATE AND TIME: January 12, 2000 - 7:00 - 9:00 p.m.

PLACE: Gainesville Regional Utilities Administration Building, Multi-purpose Room, 301 Southeast 4th Avenue, Gainesville, Florida

PURPOSE: To accept public comments and provide status of Department's Intent to Issue an Air Construction Permit to construct a combined cycle combustion turbine-electrical generator at the Gainesville Regional Utilities J.R. Kelly Generating Station located at 605 Southeast 3rd Street, Gainesville, Alachua County, Florida. The permitting action is subject to the Department's rules for the Prevention of Significant Deterioration of Air Quality and Best Available Control Technology (BACT).

A copy of the agenda and the Department's proposed permit and supporting documents can be obtained by contacting: Ms. Teresa Heron, Department of Environmental Protection at 2600 Blair Stone Road - MS 5505, Tallahassee, Florida 32399, phone (850)921-9529, or by phoning the Bureau of Air Regulation's New Source Review Section at (850)921-9533.

Pursuant to the provisions of the Americans with Disabilities Act, any person requiring special accommodations to participate in this meeting is asked to advise the agency at least 48 hours before the meeting by contacting the Personnel Service Specialist in the Bureau of Personnel at (850)488-2996. If you are hearing or speech impaired, please contact the agency by calling (800)955-8771 (TDD).

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

Jeb Bush
Governor

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

David B. Struhs
Secretary

December 20, 1999

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Mr. Gregg Worley, Chief
Preconstruction/HAP Section
US EPA Region IV
61 Forsyth Street
Atlanta, GA 30303

Re: PSD Review and Custom Fuel Monitoring Schedule
GRU J.R. Kelly Generating Station
Unit 8 Repowering Project, PSD-FL-276

Dear Mr. Neeley:

Attached is another copy for the GRU J.R. Kelly Generating Station Repowering Project in Gainesville, Alachua County. It will be a natural gas-and maximum 0.05 percent sulfur fuel oil-fired combined cycle unit.

The project will trigger PSD for CO and PM_{10}. Please provide your comments on the Draft BACT determination and Draft Permit. The project is not subject to the Florida's Power Plant Siting procedure because it will not increase steam electrical generating capacity. The Department's PSD Rules at 62-212.400., F.A.C. apply.

Please send your written comments on or approval of the applicant's proposed custom fuel monitoring schedule. The plan is based on the letter dated January 16, 1996 from Region V to Dayton Power and Light. The Subpart GG limit on SO_2 emissions is 150 ppmvd @ 15% O_2 or a fuel sulfur limit of 0.8% sulfur. Neither of these limits could conceivably be violated by the use of pipeline quality natural gas which meets the requirements of 40 CFR 75 Appendix D Section 2.3.1.4 or by back-up fuel oil with a 0.05% sulfur content. The requirements have been incorporated into the enclosed draft permit as Specific Conditions 42 and 43 and read as follows:

Natural Gas Monitoring Schedule: Monitoring of the nitrogen content of natural gas is not required because the fuel-bound nitrogen content of the fuel is minimal. Monitoring of the sulfur gas is not required if the vendor documentation indicates that the fuels meet the definitions of natural gas or pipeline natural gas (40CFR 72). A custom fuel monitoring schedule pursuant to 40 CFR 75 Appendix D for natural gas may be used in lieu of the daily sampling requirements of 40 CFR 60.334 (b)(2) provided the following requirements are met:

- The permittee shall apply for an Acid Rain permit within the deadlines specified in 40 CFR 72.30. (Application received September 7, 1999)

- The permittee shall submit a monitoring plan, certified by signature of the Designated Representative, that commits to using a primary fuel natural of gas or pipeline supplied natural gas.
- SO_2 emissions using methods consistent with the requirements of 40 CFR 75 and certified by the USEPA.

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

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

Please comment on Specific Conditions 25 and 39 which allow the use of the acid rain NO_X CEMS for demonstrating compliance as well as reporting excess emissions, as well as Specific Condition 40 which allows use of CEMS in lieu of measuring the water-to-fuel ratio. Typically NO_X emissions will be less than 10 ppmvd @15% O_2 (gas) which is about one-tenth of the applicable Subpart GG limit based on the efficiency of the unit. A CEMS requirement is stricter and more accurate than any Subpart GG requirement for determining excess emissions.

The Department recommends your approval of the custom fuel monitoring schedules and these NO_X monitoring provisions. We also request your comments on the Intent to Issue. If you have any questions on these matters please contact Teresa Heron at 850/921-9529.

Sincerely,

A. A. Linero, P.E., Administrator
New Source Review Section

AAL/aal

Enclosures

Z 031 391 906

US Postal Service

Receipt for Certified Mail

No Insurance Coverage Provided.

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Special Delivery Fee	
Restricted Delivery Fee	
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Return Receipt Showing to Whom, Date, & Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date GRLL P50-F1-276	12-20-99

PS Form **3800**, April 1995

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- Complete items 1 and/or 2 for additional services.
- Complete items 3, 4a, and 4b.
- Print your name and address on the reverse of this form so that we can return this card to you.
- Attach this form to the front of the mailpiece, or on the back if space does not permit.
- Write *"Return Receipt Requested"* on the mailpiece below the article number.
- The Return Receipt will show to whom the article was delivered and the date delivered.

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Consult postmaster for fee.

3. Article Addressed to:

Mr. Gregg Worley, Chief
Air, Radiation Technology Branch
Preconstruction/HAP Section
U.S. EPA - Region IV
61 Forsyth Street
Atlanta, GA 30303

4a. Article Number
Z 031 391 906

4b. Service Type
☐ Registered ☑ Certified
☐ Express Mail ☐ Insured
☐ Return Receipt for Merchandise ☐ COD

7. Date of Delivery

5. Received By: *(Print Name)*
JOYCE EVANS

6. Signature: *(Addressee or Agent)*
X DEC 22 1999

8. Addressee's Address *(Only if requested and fee is paid)*

Is your RETURN ADDRESS completed on the reverse side?

Thank you for using Return Receipt Service.

PS Form **3811**, December 1994 102595-98-B-0229 Domestic Return Receipt