STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF PERMIT

In the matter of an
Application for Permit by:

DER File No. PSD-FL-212
Alachua County

Mr. Michael L. Kurtz
General Manager for Utilities
Gainesville Region Utilities
Post Office Box 147117-Station A-134
Gainesville, Florida 32614-7117
______________________________/

Enclosed is Permit Number PSD-FL-212. This permit authorizes the construction of a 74 MW simple cycle combustion turbine (SCCT) in Gainesville, Alachua County, Florida, pursuant to Section(s) 403, Florida Statutes.

Any party to this Order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the Clerk of the Department in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 14 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on 4-11-95 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

(Clerk) 4-11-95 (Date)

Copies furnished to:
C. Kirts, NE District
D. Roberts, HGS&S
J. Harper, EPA
J. Bunyak, NPS
B. Oven, PPS, DEP
D. Graziani, P.E., FWI

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Michael L. Kurtz Gen. Mgr.
Gainesville Regional Utilities
P. O. BOX 147117-Station A-134
Gainesville, Fl
32614-7117

4a. Article Number
Z 311 902 936

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

7. Date of Delivery
APR 13 1995

5. Signature (Addressee)

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6. Signature (Agent)

PS Form **3811**, December 1991 ☆U.S. GPO: 1993—352-714 **DOMESTIC RETURN RECEIPT**

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Thank you for using Return Receipt Service.

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Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
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UNITED STATES POSTAL SERVICE

PS Form **3800**, March 1993

Sent to Michael Kurtz	
Street and No. GRU	
P.O., State and ZIP Code Gainesville, Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
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TOTAL Postage & Fees	$
Postmark or Date PSD-Fl-212 4-11-95	

FINAL DETERMINATION

Gainesville Regional Utilities
PSD-FL-212
Alachua County

Gainesville Regional Utilities' application for a permit to construct a 74 MW simple cycle combustion turbine (SCCT) at their facility in Gainesville, Alachua County, Florida has been reviewed by the Bureau of Air Regulation in Tallahassee. The Technical Evaluation and Preliminary Determination for the permit to construct a 74 MW SCCT in Gainesville Florida, was distributed on December 19, 1994. The Notice of Intent was published in the Gainesville Sun on December 24, 1994. Copies of the evaluation were available for inspection at the Department's offices in Gainesville, Jacksonville and Tallahassee.

No adverse comments were submitted by either the U.S. Department of Interior or the U.S. Environmental Protection Agency.

Comments regarding the Technical Evaluation and Preliminary Determination and Specific Conditions of the proposed permit were submitted by Ms. Yolanta Yonynas, Environmental Manager of Gainesville Regional Utilities, in her letter of January 23, 1995. The Bureau has considered Ms. Yonynas' comments and agreed to the changes proposed for the material covered by the "Technical Evaluation and Preliminary Determination."

The requested revisions of the specific conditions of the permit are discussed and the Department's response and any changes agreed to are as follows:

DEP PERMIT NUMBER PSD- FL-212 and SITE CERTIFICATION NO. PA74-04

A. SPECIFIC CONDITION #3

GRU'S COMMENTS:

Correct "operation of fuel oil" to "operation **on** fuel oil"

DEPARTMENT'S RESPONSE:

This sentence will be corrected in the final permit.

B. SPECIFIC CONDITION #6

GRU'S COMMENTS:

GRU requested that emissions during fuel switching and load change be addressed by revising line 6 as follows:

a) "......malfunction, **load change and fuel switching** pursuant to Rule 62-210.700, F.A.C.;"

b) GRU requested that the footnote of this condition be changed to reflect NOx emission rates only.

The footnote shall be revised for clarification as follows: "For purpose of demonstrating compliance, these values **will** be calculated using F-factors".

c) GRU requested that visible emissions during fuel oil operation be permitted at 20% considering: 1) the limited number of hours allowed on fuel oil; 2) similar projects that have recently been permitted at 20%; and, 3) the manufacturer's indication that the lower limit may not be achievable consistently at partial loads.

d) The table indicates that compliance with the PM_{10}, SO_2 and H_2SO_4 mist mass emission rates will be demonstrated through fuel sulfur analysis. It is GRU's understanding that compliance with the percent sulfur in the fuel will be deemed compliance with the mass emission rates.

DEPARTMENT'S RESPONSE:

a) This condition will not be changed as requested. The load change and fuel switching allowance was intended for fossil fuel steam generators not for combustion turbines.

b) The footnote of this condition will be revised, as requested, in the final permit.

c) This condition will not be changed as requested. Recent permits issued by the Department have included a 10% opacity limit when burning oil. This opacity standard is a specific limitation set in the BACT determination and will be used for enforcement if a violation is detected.

d) The Department's intent regarding this issue is to assume that compliance for PM and H_2SO_4 mist as long as the 0.05% sulfur content, by weight, in the fuel oil will not be exceeded. However, this doesn't mean that it is a direct relation with the mass emission rates for these pollutants. The Department, pursuant to Rule 62-297.340(2), F.A.C., may request a compliance test, when after investigation (such as compliants, increased visible emissions, or questionable maintenance of control equipment), there is reason to believe that any applicable emissions standard is being violated.

C. SPECIFIC CONDITION #7

GRU'S REQUEST:

GRU requested that this condition be revised as follows: "Visible emissions shall not exceed 10% opacity when firing natural gas or 20% opacity when firing No. 2 fuel oil.

DEPARTMENT'S RESPONSE:

This condition will not be changed. Recent permits issued by the Department have included a 10% opacity limit when burning oil. This opacity standard is a limit set in the BACT determination.

D. SPECIFIC CONDITION #8

GRU's COMMENTS

The annual emission rate (TPY) indicated in this table are not consistent with the data provided in Table 2-1 and Table 2-5 of the PSD permit applications for the ISO conditions specified. The correct values are as follows:

VOC: **8.66**
Inorganic Arsenic: **0.004854**
Mercury: **0.0009**
Pb: **0.05746**
Be: **0.00032**
b) In footnote "**" insert the word **condition** after ISO on the third line.

DEPARTMENT'S RESPONSE:

The potential emissions table of Specific Condition #8 will be changed, as requested. The column labeled PSD SIGNIFICANT EMISSION RATE (TPY) should show "any" instead of "0" under Arsenic to be consistent with EPA recommendations for significance levels for arsenic published in the 1990 draft NSR Workshop Manual page A.21. The control technology for arsenic is to fire clean, low Arsenic fuels to limit arsenic emissions. Since the permit already restricts the fuels to natural gas or distillate fuel oils, there are no further restrictions needed to minimize arsenic emissions.

E. SPECIFIC CONDITION #9

GRU'S REQUEST:

GRU requested that the following be inserted in the "Note" paragraph such that use of alternate EPA/DEP reference methods does not require approval from the Secretary.

"Note: No other method may be used for compliance testing unless prior DEP approval is received in writing. DEP approval to use other reference methods shall not constitute an alternate test method or procedure under Rule 297.620 F.A.C. The DEP..."

DEPARTMENT RESPONSE:

Pursuant to Rule 62-297.620, F.A.C., this condition will not be changed. The intent of the Rule 62-297.620, F.A.C., is to require Approval of Alternate Standard Procedures and Requirements in the following situations:

1. The substitution of a method or procedure that has not been adopted by the Department for one that has.
2. The use of a reference method for a purpose other that for which it was originally intended (substitution of EPA Method 25A for EPA Method 25).
3. The modification of an adopted procedure.

F. SPECIFIC CONDITION #10

GRU'S COMMENTS:

This condition allows natural gas supplier data to be used for demonstrating the sulfur content of the natural gas. GRU requests that fuel oil data also be allowed as an alternative consistent with 40 CFR 60.335(e) by revising line 12 as follows:

"natural gas **and fuel oil** supplier data for sulfur content may be submitted"

DEPARTMENT'S RESPONSE:

This condition will be changed as requested.

It should be noted that GRU must assume responsibility for any error by the supplier. Supplier errors will not be a defense if the Department samples the oil and finds that the sulfur content of the oil exceeds the allowable limit.

G. SPECIFIC CONDITION #12

GRU'S COMMENTS:

This condition specifies initial and annual testing requirements for the combustion turbine and states that "the combustion turbine shall operate between 95% and 100% of maximum capacity..." The permit is silent with respect to testing at less than this capacity. GRU requests that the proposed language, stated in bold, (consistent with Chapter 62-297.310(2) F.A.C.) be included to address this contingency:

FROM:

12. An initial test for CO, concurrent with each NO_x test, is required to confirm that annual potential emissions will not exceed 100 TPY. The NOx and initial CO test results shall be the average of three valid one-hour runs. The DEP's Northeast District office shall be notified, in writing, at least 30 days prior to the initial compliance tests and at least 15 days before annual compliance test(s). The combustion turbine shall operate between 95% and 100% of maximum capacity for the ambient conditions experienced during compliance test(s). The turbine manufacturer's heat input rates (based on the high heating value of the fuel) vs. ambient temperature curve shall be included with the compliance test results. The fuel feed rates and the high heating value of the fuels shall be established during the initial and annual compliance tests. Compliance test results shall be submitted to the DEP's Northeast District office no later than 45 days after completion of the last test run.

TO:

12. An initial test for CO, concurrent with each NO_x test, is required to confirm that annual potential emissions will not exceed 100 TPY. The NOx and initial CO test results shall be the average of three valid one-hour runs. The DEP's Northeast District office shall be notified, in writing, at least 30 days prior to the initial compliance tests and at least 15 days before annual compliance test(s). **"Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 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 v. 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 v. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity."** Compliance test results shall be submitted to the DEP's Northeast District office no later than 45 days after completion of the last test run.

DEPARTMENT'S RESPONSE:

This condition is acceptable as proposed. Specific Condition #12 is changed as requested.

H. SPECIFIC CONDITION #13

This condition addresses excess NOx emissions, which may occur due to temporary and unavoidable combustion instability under certain operating conditions (e.g. startup, load change, fuel switching, etc.) Excess visible emissions may also result under these conditions. Therefore, GRU requests that these be addressed in the same manner as NOx emissions as follows:

Excess NOx and visible emissions from this turbine resulting from startup, shutdown,.."

DEPARTMENT'S RESPONSE:

This condition will not be changed. To use load change and fuel switching as a valid excess emissions conditions is not acceptable. The allowance referenced in Rule 62-210.700, F.A.C., was intended for fossil fuel steam generators.

I. SPECIFIC CONDITION #14

GRU'S COMMENTS:

Condition 14c states that notification and recordkeeping shall be in accordance with 40 CFR 60.7. Subsection (c) states that records shall be maintained for a period of five (5) years. This is inconsistent with 40 CFR 60.7(f), which specifies a two years retention time. GRU requests that this condition be revised as follows:

"c. All measurements...shall be retained for at least two years period."

DEPARTMENT'S RESPONSE:

This condition will not be changed. Although it is true that section 40 CFR 60.7(e) specifies two (2) years retention period, Rule 62-4.160(14)(b), F.A.C., requires the permittee to retain, all records for <u>at least</u> three years period. This is a General Condition of every Department permit (General Condition 14b). To be consistent with Title V regulations we are now requiring records to be maintained for a period of five (5) years pursuant to Rule 213.440(1)(b)2.b., F.A.C.

J. SPECIFIC CONDITION #15

GRU'S COMMENTS:

a) This condition defines excess emissions as one-hour periods when NOx emissions are above the BACT standards. GRU requests that this period be revised, as indicated below, to reflect the agreement reached at the September 2, 1994 meeting between GRU and the Department.

" Twenty-four hour block average (midnight to midnight) periods.".

b) Correct typographical error : Rule 62-297.520 F.A.C.

DEPARTMENT'S RESPONSE:

This condition will not be changed.

One-hour periods shall be as specified in 40 CFR 60.334(1). The previous agreement was made under the assumption the applicant would use a CEM to determine compliance. The current permit allows the applicant to use the CEM in place of the water/fuel monitoring required in 40 CFR 60.334 for assessment of excess emissions. In addition, NOx compliance in Subpart GG is by EPA Method 20, which requires three 1-hour runs.

The typographical error was corrected.

K. SPECIFIC CONDITION #17

GRU'S REQUEST:

GRU requests this condition be revised, as indicated below, to conform to the monitoring and recordkeeping specified 40 CFR 60.334(b) and 40 CFR 60.7 (e), respectively.

"...will be recognized as enforceable ~~provisions-of-the-permit provided-that-the-holder-of-this-permit-demonstrates-that-the provisions-of-the-schedule-will-be-adequate-to-assure-continuous compliance~~. The records...shall be kept by the ~~company~~ permittee for a ~~five~~ two-year period for regulatory agency inspection purposes."

Also, DEP approval of a custom monitoring schedule should be indicative of the Department's satisfaction that it is adequate for compliance purposes.

DEPARTMENT'S RESPONSE:

This condition is changed pursuant to 40 CFR 60.334(b). The five (5) year period is consistent with Rule 213.440(1)(2)2.b., F.A.C.

FROM:

17. The sulfur content of the fuel oil being fired in the combustion turbine shall be determined in accordance with 40 CFR 60.334(b) (1993 version). Any request for a future custom monitoring schedule shall be made in writing and directed to the DEP's Bureau of Air Regulation office. Any custom schedule approved by the DEP pursuant to 40 CFR 60.334(b) (1993 version) will be recognized as enforceable provisions of the permit, provided that the holder of this permit demonstrates that the provisions of the schedule will be adequate to assure continuous compliance. The records of natural gas and No. 2 fuel oil usage shall be kept by the company for a five-year period for regulatory agency inspection purposes.

TO:

17. The sulfur content of the fuel oil being fired in the combustion turbine shall be determined in accordance with 40 CFR 60.334(b) (1993 version). **Any request for a future custom schedule shall be made in writing and directed to the EPA's office in Atlanta and the DEP's Bureau of Air Regulation office. Any custom schedule approved by EPA and DEP pursuant to 40 CFR 60.334 (b) (1993 version) will be recognized as enforceable provisions of the permit. The records of natural gas and No. 2 fuel oil usage shall be kept by the company for a five (5) years period for regulatory agency inspection purposes.**

L. SPECIFIC CONDITION #18

GRU'S COMMENTS:

This condition states that the unit will be in compliance with all applicable provisions of Chapter 62-296, F.A.C., which includes the New Source Performance Standards for Combustion Turbines (Subpart GG). Certain permit conditions, however, provide alternatives to these provisions. For example, Specific Condition 15 requires continuous monitoring of NOx emissions in lieu of monitoring the water to fuel ratio and fuel-bound nitrogen as required by Subpart GG. Therefore, GRU requests that this condition acknowledge any alternate provisions contained in this permit as follows:

The emission unit shall be in compliance with...F.A.C., <u>except as otherwise specified herein."</u>

DEPARTMENT'S RESPONSE:

This condition is modified as proposed:

FROM:

18. The emission unit shall be in compliance with all applicable provisions of Chapter 403, F.S., and Chapters 62-4, 210, 212, 275, 296 and 297, F.A.C.

TO:

18. The emission unit shall be in compliance with all applicable provisions of Chapter 403, F.S., and Chapters 62-4, 210, 212, 275, 296 and 297, F.A.C., **except as otherwise specified herein.**

M. SPECIFIC CONDITION #19:

GRU'S COMMENTS:

This condition requires compliance with all applicable requirements of Subpart GG. For the reason stated above, GRU requests that this condition be revised as follows:

FROM:

19. The emission unit shall be in compliance with all applicable requirements of 40 CFR 60, Subpart A, Appendix A and Appendix B (1993 version), Subpart GG - Standards of Performance for Stationary Gas Turbines (1993 version), and Rule 62-296.800(2)(a), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). All notifications and reports required by this specific condition shall be submitted to the DEP's Northeast District office.

TO:

19. The emission unit shall be in compliance with all applicable requirements of 40 CFR 60, Subpart A, Appendix A and Appendix B (1993 version), Subpart GG - Standards of Performance for Stationary Gas Turbines (1993 version), and Rule 62-296.800(2)(a), F.A.C., **except as otherwise specified herein.** The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). All notifications and reports required by this specific condition shall be submitted to the DEP's Northeast District office.

DEPARTMENT'S RESPONSE:

This condition is changed as requested.

N. SPECIFIC CONDITION #21

GRU'S REQUEST:

As proposed in Specific Condition #19, above, is requested similar revision of this condition as follows:
"Except as otherwise specified herein, the emission unit...(NSPS)

FROM:

21. The emission unit shall be in compliance with all applicable provisions of Rule 62-210.650, F.A.C.: Circumvention; Rule 62-210.700, F.A.C.: Excess Emissions; Rule 62-296.800, F.A.C.: Standards of Performance for New Stationary Sources (NSPS); Chapter 62-297, F.A.C.: Stationary Sources - Emissions Monitoring; and, Rule 62-4.130, F.A.C.: Plant Operation - Problems.

TO:

21. **Except as otherwise specified herein**, the emission unit shall be in compliance with all applicable provisions of Rule 62-210.650, F.A.C.: Circumvention; Rule 62-210.700, F.A.C.: Excess Emissions; Rule 62-296.800, F.A.C.: Standards of Performance for New Stationary Sources (NSPS); Chapter 62-297, F.A.C.: Stationary Sources - Emissions Monitoring; and, Rule 62-4.130, F.A.C.: Plant Operation - Problems.

DEPARTMENT'S RESPONSE:

This condition is modified as requested.

O. SPECIFIC CONDITION #27

GRU'S REQUEST:

This condition states than an application for an operation permit must be submitted at least 90 days prior to expiration of the construction permit. This unit is being permitted as a modification to an existing Site Certification pursuant to the Florida Power Plant Siting Act. Therefore, an operating permit under Chapter 62-210, F.A.C., is not required. The new unit, however, will be a Title V source subject to the permitting requirements of Rule 62-213.420, F.A.C. Pursuant to Rule 62-213.420(1)(a)(2), F.A.C., an application for an operation permit (which is to be issued by Tallahassee, not the District) is to be filed no later than 180 days after commencing operation. Therefore, GRU requests that this condition be revised accordingly as follows:

FROM:

27. An application for an operation permit must be submitted to the Northeast District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the permittee shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (Rules 62-4.055 and 62-4.220, F.A.C.).

TO:

27. An application for **a Title V** operation permit must be submitted to the **Tallahassee** office **no later than 180 days after commencing operation. The permittee shall submit a timely and complete permit application in compliance with the requirements of Rule 62-213.420, F.A.C.** To properly apply for an operation permit, the permittee shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (Rules 62-4.055 and 62-4.220, F.A.C.).

DEPARTMENT'S RESPONSE:

This condition is modified as requested.

BACT DETERMINATION

GRU also requested that the Department reconsider Power Augmentation and Fuel Bound Nitrogen (issues).

DEPARTMENT'S RESPONSE:

Power Augmentation:

The power augmentation (PA) mode will allow the firing of additional natural gas, while inject water into the turbine, to produce more megawatts during peak-demand periods. NOx emissions will increase up to 30 ppmvd during PA operation. GRU states that PA is not the preferred mode of operation due to the increased wear and tear on the machine and resultant increase in maintenance costs. The Department has reconsidered this issue but maintains its previous position. The Department does not have the authority to permit the violation of a BACT determination (BACT limit shall not exceed 15 ppmvd). In life threatening situations (severe cold, hurricane, etc.), sources have been granted an emergency order allowing a temporary violation of the air permit standards by the Department's Secretary. This has been done on a case by case basis.

Fuel Bound Nitrogen:

An allowance of 12 ppm (above the 42 ppm BACT standard) was requested by GRU because water injection, the control technology utilized during fuel oil combustion, controls thermal NOx but does not control organic NOx associated with nitrogen in the fuel oil. Therefore, if the fuel oil contained significant levels of nitrogen (above 0.015%), the water injection to the unit would have to be increased beyond the manufacturer's recommended levels in order to meet the NOx limit. This would not only significantly increase water consumption, but result in increased wear and tear on the unit and additional maintenance costs.

The Department has reconsidered this issue and maintains its previous position. No allowance will be granted for fuel bound nitrogen. Similar facilities have been permitted at 15 ppmvd at 15% O_2 and have demonstrated compliance with the standard.

Conclusion:

The final action of the Department is to issue the federal construction permit, PSD-FL-212, with the changes noted above.

ATTACHMENTS AVAILABLE UPON REQUEST

Department of Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

PERMITTEE:
Gainesville Regional Utilities
P. O. Box 147117, Station A-134
Gainesville, FL 32614-7117

Permit Number: PSD-FL-212
Expiration Date: June 30, 1996
County: Alachua
Latitude/Longitude: 29°45'32"N 82°23'26"W
Project: A 74 MW Simple Cycle Combustion Turbine (DHCT3)

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.); Chapters 62-210 through 62-297 and 62-4, Florida Administrative Code (F.A.C.); and, 40 CFR 52.21 and 60. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department of Environmental Protection (Department) and specifically described as follows:

Construction of a 74 MW simple cycle combustion turbine designed to burn natural gas and No. 2 fuel oil. Deerhaven combustion turbine (DHCT3) will be constructed/installed at the Gainesville Regional Utilities (GRU)'s existing facility that is located near U.S. 441/SR20/SR25. The UTM coordinates are Zone 17, 365.5 km East and 3292.7 km North.

The emissions unit shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:

1. GRU's letter received October 20, 1993.
2. GRU's letter received December 29, 1993.
3. Construction Permit application received March 22, 1994.
4. Department's letter dated April 22, 1994.
5. GRU's letter with attachments received April 25, 1994.
6. GRU's letter with attachments received August 12, 1994.
7. GRU's letter with attachments received September 21, 1994.
8. Technical Evaluation and Preliminary Determination dated December 16, 1994.
9. GRU's letter with attachments dated May 5, 1994.

GENERAL CONDITIONS:

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

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

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

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

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

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

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a

GENERAL CONDITIONS:

reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any records that must be kept under the conditions of the permit;

b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,

c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

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

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

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

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

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

11. This permit is transferable only upon Department approval in accordance with Rules 62-4.120 and 62-30.300, F.A.C., as applicable.

GENERAL CONDITIONS:

The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

13. This permit also constitutes:

    (x) Determination of Best Available Control Technology (BACT)
    (x) Determination of Prevention of Significant Deterioration (PSD)
    (x) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

        - the date, exact place, and time of sampling or measurements;
        - the person responsible for performing the sampling or measurements;
        - the dates analyses were performed;
        - the person responsible for performing the analyses;
        - the analytical techniques or methods used; and,
        - the results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee

GENERAL CONDITIONS:

becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS:

General Operating Requirements

1. The maximum heat input rates, based on high heating values of each fuel, to the DHCT3 and at ISO conditions (i.e., 59° F, 60% relative humidity and 101.3 kilopascals pressure), shall not exceed 971.1 MMBTU/hr, while firing natural gas, nor 990.6 MMBTU/hr, while firing fuel oil. Heat input will vary depending on ambient conditions and the DHCT3 characteristics. Manufacturer's curves or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) at least 90 days before initial compliance testing.

2. The DHCT3 is allowed to operate up to 3900 hours per year, but not to exceed 2000 hours while firing fuel oil.

3. Only natural gas (NG) or No. 2 fuel oil shall be fired in the combustion turbine. The maximum sulfur content of the fuel oil shall not exceed 0.05 percent, by weight. GRU has established that there is approximately 55 hours of full load operation of fuel oil, which contains nominally 0.25% sulfur content, by weight, remaining in the fuel storage tank. GRU will be allowed to deplete this reserve by firing the fuel oil in the DHCT3. However, all future deliveries of fuel oil for the DHCT3 shall meet the BACT requirement, which limits the fuel oil sulfur content to no more than 0.05%, by weight. Fuel sulfur content shall be determined and recorded each time fuel is transferred into the bulk storage tank(s).

4. 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 pursuant to Rule 62-296.310(3), F.A.C. - Unconfined Emissions of Particulate Matter.

5. Any change in the method of operation, equipment or operating hours, pursuant to Rule 62-212.200, F.A.C., Definitions - Modifications, shall be submitted in writing and/or on an application to the DEP's Bureau of Air Regulation office and Northeast District office.

SPECIFIC CONDITIONS:

Emission Limits

6. The maximum allowable emissions from the DHCT3, when firing natural gas or No. 2 fuel oil, in accordance with the BACT determination, and at 95 - 100% percent load based on the manufacturer's curves submitted to the DEP, shall not exceed the following limits except during periods of start up, shutdown, and malfunction load change and fuel switching pursuant to Rule 62-210.700, F.A.C.:

MAXIMUM ALLOWABLE EMISSION LIMITS

POLLUTANT	FUEL	BACT STANDARD	LBS/HR	TPY
NO_x*	Gas	15 ppmvd @ 15% Oxygen	58	113(a)
	Oil	42 ppmvd @ 15% Oxygen	184	184(b)
			Combined(c)	239
PM_{10}	Gas	Good combustion; visible emissions shall not exceed 10% opacity	7(d)	14(a)(d)
	Oil	Good combustion of low sulfur oil; visible emissions shall not to exceed 10% opacity	15(d)	15(b)(d)
			Combined(c)	22
SO_2	Gas	Good combustion	29(d)	57(a)(d)
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	53(d)	53(b)(d)
			Combined(c)	81
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		
H_2SO_4 Mist	Gas	Good combustion	3(d)	6(a)(d)
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	6(d)	6(b)(d)
			Combined(c)	9
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		

*These values will be calculated using F factors.
(a) Based on a maximum of 3900 hours of operation with natural gas firing.
(b) Based on a maximum of 2000 hours of operation with fuel oil firing.
(c) Based on 1900 hours natural gas firing and 2000 hours of operation with fuel oil firing.
(d) Compliance shall be demonstrated through fuel sulfur analysis.

SPECIFIC CONDITIONS:

7. Visible emissions shall not exceed 10% opacity when firing natural gas or No. 2 fuel oil.

8. The potential emissions projected from the DHCT3 are:

ESTIMATED POTENTIAL EMISSIONS

Pollutant	Method of Control	TPY **
CO	Good combustion, proper use of water injection system	95.4
VOC	Good combustion	8.66
Inorganic Arsenic	Natural Gas/No. 2 Fuel Oil	0.004854
Mercury	Natural Gas/No. 2 Fuel Oil	0.0009
Pb	Natural Gas/No. 2 Fuel Oil	0.05746
Be	Natural Gas/No. 2 Fuel Oil	0.00032

** TPY values are for annual operation reports (AOR) and PSD applicability determinations. These values are based on the DHCT3 operating at full load at ISO conditions for a total of 3900 hours per year, with up to 2000 hours of No. 2 fuel oil-fired operation.

Compliance Determination

9. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate at which this unit will be operated, but not later than 180 days of initial operation at the maximum capability of the unit and annually thereafter, by using the following reference methods as described in 40 CFR 60, Appendix A (1993 version), and adopted by reference in Chapter 62-297, F.A.C.

Initial (I) compliance tests shall be performed on the DHCT3 while firing each fuel (gas, oil). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.340, F.A.C., on the DHCT3 with the fuel(s) used for more than 400 hours in the preceding 12-month period.

- Method 9 Visual Determination of the Opacity of Emissions from Stationary Sources (I,A)

SPECIFIC CONDITIONS:

- Method 10 Determination of Carbon Monoxide Emissions from Stationary Sources (I)

- Method 20 Determination of Nitrogen Oxides and Diluent Emissions from Stationary Gas Turbines (I,A)

Note: No other methods may be used for compliance testing unless prior DEP approval is received in writing. The DEP may request a special compliance test pursuant to Rule 62-297.340(2), 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.

10. Notwithstanding the requirements of Rule 62-297.340, F.A.C., the exclusive use of fuel oil with a maximum sulfur content limit of 0.05% or less, by weight, is the method for determining compliance for SO_2, H_2SO_4 mist, and PM_{10}. There is no suitable method for the testing of PM_{10} from this type of emissions unit, and the SO_2 and H_2SO_4 emissions are clearly limited by the sulfur content of the fuel. Compliance with the SO_2 and sulfuric acid mist emission limits shall be determined by fuel oil analysis using ASTM D2880-71 or D4294 (or equivalent) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel. Alternatively, natural gas and fuel oil supplier data for sulfur content may be submitted. However, the applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. 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) (1993 version).

11. Pursuant to Rule 62-212.410, F.A.C., the permittee shall install a dry low-NO_x combustor on the DHCT3 for NO_x control when firing natural gas. Control of NO_x when firing No. 2 fuel oil shall be accomplished by water injection.

12. An initial test for CO, concurrent with each NO_x test, is required to confirm that annual potential emissions will not exceed 100 TPY. The NOx and initial CO test results shall be the average of three valid one-hour runs. The DEP's Northeast District office shall be notified, in writing, at least 30 days prior to the initial compliance tests and at least 15 days before annual compliance test(s). Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 percent of the maximum heat input rate allowed by the permit, corrected for the average ambient air

SPECIFIC CONDITIONS:

temperature during the test (with 100 percent represented by a curve depicting heat input v. 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 v. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input (corrected for ambient temperature) and 105 percent of the value reached during the test until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purposes of additional compliance testing to regain the permitted capacity. Compliance test results shall be submitted to the DEP's Northeast District office no later than 45 days after completion of the last test run.

13. Excess NO_x emissions from this turbine resulting from startup, shutdown, malfunction, fuel switching or load change, shall be acceptable providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the DEP's Bureau of Air Regulation or the Northeast District office for a longer duration. Best operating practices shall be documented in writing and a copy submitted to the DEP's Northeast District office along with the initial compliance test data. The document may be updated as needed with all updates submitted to the DEP's Northeast District office within thirty (30) days of implementation and shall include time limitations on excess emissions caused by turbine startup.

Notification, Reporting and Recordkeeping

14. Notification and recordkeeping shall be in accordance with 40 CFR 60.7 (1993 version). The following protocols shall be submitted to the DEP's Northeast District office for approval:

a. CEMS - If applicable, the Federal Acid Rain Program requirements of 40 CFR 75 shall apply when those requirements become effective in Florida.

b. Performance Test Protocol - At least 30 days prior to conducting the initial performance tests required by this permit, the permittee shall submit to the DEP's Northeast District office for their review and approval: a protocol outlining the procedures to be followed; the test methods; and, any differences between the reference methods and the test methods proposed to be used to verify compliance with the conditions of this permit.

SPECIFIC CONDITIONS:

c. All measurements, records, and other data required to be maintained by GRU shall be retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These data shall be made available to the DEP representatives.

Monitoring Requirements

15. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from this source. One-hour periods when NO_x emissions (ppmvd @ 15% oxygen) are above the BACT standards (15/42 gas/oil) shall be reported as excess emissions following the format of 40 CFR 60.7 (1993 version). The continuous emission monitor must comply with Rule 62-297.520, F.A.C.; 40 CFR 60, Appendix F, Quality Assurance Procedures (1993 version) (or other DEP approved QA plan); 40 CFR 60, Appendix B, Performance Specification 2 (1993 version); or, if applicable, 40 CFR 75, Appendix A and Appendix B. Periods of startup, shutdown, fuel switching, malfunction, and load change shall be monitored and recorded. The NO_x CEMS will be used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring, which are required in accordance with 40 CFR 60, Subpart GG (1993 version), and are used as indicators of compliance with the NO_x standard specified in the subpart. Since the NO_x emission standard from Subpart GG is more than twice the BACT standard, monitoring for emissions in excess of the BACT limits using the NO_x CEMS is more stringent. FBN levels are not required for excess emission reports when excess emissions are reported and based on the stack monitoring system. The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) (1993 version) will be replaced by certification tests of the NO_x CEMS.

16. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions and shall be prohibited pursuant to Rule 62-210.700, F.A.C.

17. The sulfur content of the fuel oil being fired in the combustion turbine shall be determined in accordance with 40 CFR 60.334(b) (1993 version). Any request for a future custom schedule shall be made in writing and directed to the EPA's office in Atlanta and the DEP's Bureau of Air Regulation office. Any custom schedule approved by EPA and DEP pursuant to 40 CFR 60.334 (b) (1993 version) will be recognized as enforceable provisions of the

SPECIFIC CONDITIONS:

permit. The records of natural gas and No. 2 fuel oil usage shall be kept by the company for a five (5) years period for regulatory agency inspection purposes.

Rule Requirements

18. The emission unit shall be in compliance with all applicable provisions of Chapter 403, F.S., and Chapters 62-4, 210, 212, 275, 296 and 297, F.A.C., except as otherwise specified herein.

19. The emission unit shall be in compliance with all applicable requirements of 40 CFR 60, Subpart A, Appendix A and Appendix B (1993 version), Subpart GG - Standards of Performance for Stationary Gas Turbines (1993 version), and Rule 62-296.800(2)(a), F.A.C., except as otherwise specified herein. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). All notifications and reports required by this specific condition shall be submitted to the DEP's Northeast District office.

20. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (Rule 62-210.300(1), F.A.C.).

21. Except as otherwise specified herein, the emission unit shall be in compliance with all applicable provisions of Rule 62-210.650, F.A.C.: Circumvention; Rule 62-210.700, F.A.C.: Excess Emissions; Rule 62-296.800, F.A.C.: Standards of Performance for New Stationary Sources (NSPS); Chapter 62-297, F.A.C.: Stationary Sources - Emissions Monitoring; and, Rule 62-4.130, F.A.C.: Plant Operation - Problems.

22. If construction does not commence within 18 months of issuance of this permit, the permittee shall obtain from the DEP's Bureau of Air Regulation a review and, if necessary, a modification of the BACT determination and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2) (1993 version)).

23. Quarterly excess emission reports, in accordance with 40 CFR 60.7 and 60.334 (1993 version), shall be submitted to the DEP's Northeast District office.

24. Pursuant to Rule 62-210.370(2), F.A.C., Annual Operating Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following:

SPECIFIC CONDITIONS:

sulfur content of the fuel being fired, fuel usage, hours of operation, air emissions limits, etc. Annual operating reports shall be sent to the DEP's Northeast District office by March 1st of each calendar year.

25. Stack sampling facilities shall be installed in accordance with Rule 62-297.345, F.A.C.

26. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.090, F.A.C.).

27. An application for a Title V operation permit must be submitted to the Tallahassee office no later than 180 days after commencing operation. The permittee shall submit a timely and complete permit application in compliance with the requirements of Rule 62-213.420, F.A.C. To properly apply for an operation permit, the permittee shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (Rules 62-4.055 and 62-4.220, F.A.C.).

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell

Virginia B. Wetherell
Secretary

Best Available Control Technology (BACT) Determination
Gainesville Regional Utilities
Alachua County

PSD-FL-212

Gainesville Regional Utilities (GRU) proposes to construct a 74 MW (nominal) simple cycle combustion turbine (CT) at the existing Deerhaven site approximately seven miles north of Gainesville in Alachua County. The selected CT, designated as DHCT3, is a GE Model MS 7001 EA with dry low-NO_x combustors and will also use water injection for NO_x control when firing fuel oil.

The applicant requested approval to operate the emission unit for 3900 hours per year, as indicated in the table below. The No. 2 fuel oil will have a maximum limit of 0.05 percent sulfur content, by weight. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the combustion turbine at 100 percent load, at 15% O_2 and ISO conditions (59°F, 60% relative humidity, and 101.3 kilopascals pressure), for each type of fuel fired, to be as follows:

Pollutant	Emissions (TPY) Gas	Gas w/PA *	Oil	Total	PSD Significant Emission Rate (TPY)
	1510 Hrs	390 Hrs	2000 Hrs		
NO_x	40	23	213	276	40
SO_2	20	6	48	74	40
PM/PM_{10}	5	1	15	21	25/15
CO	24	8	65	97	100
VOC	2	1	6	9	40
H_2SO_4 mist	2	1	5	8	7
Be			0.00032	0.00032	0.0004
Hg			0.0009	0.0009	0.1
Pb			0.05746	0.05740	0.6
As			0.004854	0.004854	Any

* with power augmentation

Rule 62-212.400(2)(f)(1), Florida Administrative Code (F.A.C.), requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the table above. Therefore, BACT is required for NO_x, SO_2, PM_{10}, and H_2SO_4 mist.

Date of Receipt of a BACT Application

March 25, 1994

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	15 ppmvd @ 15% O_2 (natural gas firing) 54 ppmvd @ 15% O_2 (for No. 2 fuel oil firing), maximum based on fuel bound nitrogen 30 ppmvd @ 15% O_2 (natural gas firing-power augmentation mode). Dry low-NOx combustor when firing natural gas and water injection when firing distillate oil and during power augmentation mode.
PM_{10}	Prefiltering of the combustion air, good combustion practices, and use of natural gas as the primary fuel with limited annual fuel oil firing.
SO_2	0.05% sulfur content by weight (fuel oil firing); also, an equivalent of up to 55 hours of full load operation at ISO conditions using a fuel oil with a maximum of 0.25% sulfur content, by weight.
H_2SO_4 Mist	0.05% sulfur by weight (fuel oil firing), also, an equivalent of up to 55 hours of full load operation at ISO conditions using a fuel oil with a maximum of 0.25% sulfur content, by weight.

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:

(a) 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).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determination of any other state.

(d) 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 infeasible 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 air pollutant emissions from simple cycle combustion turbines can be grouped into categories based upon the control equipment and techniques that are available to control emissions from these emission units. Using this approach, the emissions can be classified as follows:

- o Combustion Products (e.g., particulate matter). Controlled generally by good combustion of clean fuels.
- o Products of Incomplete Combustion (e.g., carbon monoxide). Control is largely achieved by proper combustion techniques.
- o Acid Gases (e.g., nitrogen oxides). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulate matter, sulfur dioxide, fluorides, sulfuric acid mist, etc,), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

<u>ACID GASES</u>

Nitrogen Oxides (NOx)

The emissions of nitrogen oxides represent a significant portion of the total emissions generated by this project, and need to be controlled as deemed appropriate. As such, the applicant presented an extensive analysis of the different available technologies for NO_x control.

The applicant stated that BACT for nitrogen oxides will be met by using dry low-NO_x combustor design to limit emissions to 15 ppmvd (corrected to 15% O_2), when burning natural gas; and, by water injection to limit emissions to the applicant's proposed BACT level of up to 54 ppmvd (corrected to 15% O_2), when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NO_x emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system on two 25 MW combustion turbines located in Kern County, California.

SCR is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction efficiency (while holding ammonia slip emissions constant) will decrease.

The effect of exhaust gas temperature on NOx reduction depends on the specific catalyst formulation and reactor design. Generally, SCR units can be designed to achieve effective NOx control over a 100-300°F operating window within the bounds of 450-800°F, although recently developed zeolite-based catalysts are claimed to be capable of operating at temperatures as high as 950°F.

Most commercial SCR systems operate over a temperature range of about 600-750°F. At levels above and below this window, the specific catalyst formulation will not be effective and NO_x reduction will decrease. Operating at high temperatures can permanently damage the catalyst through sintering of surfaces.

Increased water vapor content in the exhaust gas (as would result from water or steam injection in the gas turbine combustor) can shift the operating temperature window of the SCR reactor to slightly higher levels.

The exhaust temperatures of the proposed simple cycle CT for this site will range from 955°F to 1,100°F. At temperatures of 1,100°F and above, the zeolite catalyst (reported to operate to a maximum temperature of 1,050°F) will be irreparably damaged.

Based on the GE data sheets for the proposed DHCT3 provided by the applicant, exhaust temperatures will range from 955°F to 1,100°F, depending upon the fuel fired, ambient temperature and load. Since the zeolite catalysts were reported to operate in this temperature range, ENSERCH Environmental investigated the technical feasibility of using such a system. Because the zeolite catalysts are new, only one vendor (Norton Chemical Process Products Corporation, P.O.

Box 350, Akron, Ohio 44309-0350) was capable of providing a cost estimate. A second vendor was contacted and a cost estimate was requested, but no response was received. This cost estimate noted that the current zeolite catalyst is limited to a maximum upper temperature of 1,050°F and, without an air injection system to cool the exhaust gases at the zeolite catalyst, its use would be infeasible. Review of the GE data sheets for the Deerhaven CT confirmed the vendor's exhaust gas temperature findings. ENSERCH Environmental requested that the vendor revise the initial cost estimate and include the cost of an air injection system.

Based on the information obtained from the vendor, the use of a SCR system equipped with a zeolite catalyst and an air injection system was deemed to be only potentially technically feasible based upon its limited usage on simple cycle CTs. In addition, although the concept of an air injection system is easily visualized, its use commercially has been documented only once in the clearinghouse as a commercially available response to the temperature limitations of SCR. Although only potentially technically feasible, ENSERCH Environmental evaluated the impacts of a SCR system equipped with a high temperature zeolite catalyst and an air injection system as the available post-combustion control technology needed to meet the most stringent emission limitations.

For the simple cycle combustion turbine and based on the information supplied by the applicant, it is estimated that the maximum annual NO_X emissions using a low-NO_X combustor will be 276.42 tons/year. Assuming that SCR would reduce the NO_X emissions by approximately 80%, about 58.22 tons of NO_X would be emitted annually. When this reduction is taken into consideration alone with the total levelized annual operating cost of $1,455,957.33, the incremental cost effectiveness ($/ton) of controlling NO_X is $6,672.58 for this project. These calculated costs are higher than costs previously approved as BACT.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (H_2SO_4)

The applicant stated that the sulfur dioxide (SO_2) and sulfuric acid (H_2SO_4) mist emissions, when firing No. 2 fuel oil, will be controlled by using fuel oil with a maximum sulfur content limit of 0.05%, by weight. This will result in an annual emission rate of 81 tons SO_2 per year and 9 tons H_2SO_4 mist per year (with no power augmentation, operating at 1900 hours per year on natural gas, and operating 2000 hours per year on No. 2 fuel oil with a maximum limit of 0.05% sulfur content, by weight).

In accordance with the "top down" BACT review approach, only two alternatives exist that would result in more stringent SO_2 emissions. These include the use of a lower sulfur content fuel oil or the use of wet lime or limestone-based scrubbers, otherwise known as flue gas desulfurization (FGD).

In developing the NSPS for stationary gas turbines, EPA recognized that FGD technology was inappropriate to apply to these combustion units. EPA acknowledged in the preamble of the proposed NSPS that "Due to the high volumes of exhaust gases, the cost of flue gas desulfurization (FGD) to control SO_2 emission from stationary gas turbines is considered unreasonable." EPA reinforced this point when, later in the preamble, they stated that "FGD...would cost about two to three times as much as the gas turbine." The economic impact of applying FGD today is no different.

Furthermore, the application of FGD would have negative environmental and energy impacts. Sludge would be generated that would have to be disposed of properly and there would be increased utility (electricity and water) costs associated with the operation of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

The elimination of flue gas control as a BACT option leaves the use of low sulfur fuel oil as the next option to be investigated. Gainesville Regional Utilities, as stated above, has proposed the use of No. 2 fuel oil with no more than 0.05% sulfur content, by weight, as BACT for this project.

Particulate Matter (PM) Emissions

Particulate matter (PM) emissions from combustion turbines are related to the combustion air, fuel quality and combustion efficiency. Review of the BACT/LAER Clearinghouse indicates that most combustion turbines meet the BACT requirement through filtering the combustion air, good combustion practices, use of clean burning natural gas and limited fuel oil firing. Currently, post combustion controls (i.e., baghouse) are not being used on combustion turbines. This is due mostly to the characteristics of the exhaust gases (high temperatures and velocities) and the low emissions rates for PM when good combustion of low sulfur fuels is employed.

PM_{10} (PM less than 10 microns in diameter) emissions result from noncombustibles in the fuels, PM_{10} in the ambient air used as combustion air, dissolved solids in the water used for wet injection, and incomplete combustion. Since solids can damage the combustion turbine, considerable efforts are made to limit their entry and/or formation. Based on this need and review of the BACT/LAER Clearinghouse data, the applicant proposes prefiltering of the combustion air, good combustion practices, and use of natural gas as the primary fuel and limited annual fuel oil firing as BACT.

BACT Determination by the Department

NO_x Control

The information that the applicant presented and Department calculations indicate that the cost per ton of controlling NO_x for this turbine [$6,672.58 per ton] is high compared with other BACT determinations, which required SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_x control is not justifiable as BACT.

It is the Department's understanding that General Electric is developing controls using either steam/water injection or dry low-NO_x combustor technology to achieve a NO_x emission control level of 9 ppm when firing natural gas. Several prior CT projects have already been permitted at 15 ppmvd @ 15% O_2 (natural gas) and 42 ppmvd @ 15% O_2 (No. 2 fuel oil). In these BACT determinations, no allowance has been made for fuel bound nitrogen or for operation with power augmentation. The Department has determined that BACT for this project is 15 ppmvd @ 15% O_2 using natural gas and 42 ppmvd @ 15% O_2 when firing No. 2 fuel oil. Measured NO_x concentrations shall not be corrected to ISO conditions to determine compliance with these BACT standards. Based on emission rates at the worst case design ambient conditions (20°F) supplied by GE, NO_x emissions will also be limited to 58 lbs/hr for natural gas firing and 184 lbs/hr for fuel oil firing.

SO_2 and H_2SO_4 Mist Control

The Department accepts the applicant's proposal as BACT for sulfur dioxide and H_2SO_4 mist, which is the burning of either natural gas or No. 2 fuel oil with a maximum limit of 0.05% sulfur content, by weight. Fuel oil usage will be limited to no more than 2000 hours per year. GRU has estimated that there is approximately 55 hours of full load operation of fuel oil at 0.25% sulfur content, by weight, remaining in the fuel oil storage tank. GRU will be allowed to deplete this reserve of fuel oil. However, all future deliveries of fuel oil shall meet the BACT requirements, which is a maximum limit of 0.05% sulfur content, by weight.

PM_{10} Control

The Department accepts the applicant's proposed BACT for this emission unit. PM_{10} emissions from fuel burning are related to the sulfur content of the fuel and combustion practices. PM_{10} emissions will be controlled by good combustion practices and firing natural gas; or, firing No. 2 fuel oil for no more than 2000 hours per year. The No. 2 fuel oil shall be limited to no more than 0.05% sulfur content, by weight. In addition, visible emissions shall not exceed 10% opacity when firing natural gas or fuel oil.

BACT Standards

The BACT emission limits for the Gainesville Regional Utilities project, a DHCT3, are established as follows:

MAXIMUM ALLOWABLE EMISSION LIMITS

POLLUTANT	FUEL	BACT STANDARD	LBS/HR	TPY
NO_x*	Gas	15 ppmvd @ 15% Oxygen	58	113(a)
	Oil	42 ppmvd @ 15% Oxygen	184	184(b)
			Combined(c)	239
PM_{10}	Gas	Good combustion; visible emissions shall not exceed 10% opacity	7(d)	14(a)(d)
	Oil	Good combustion of low sulfur oil; visible emissions shall not to exceed 10% opacity	15(d)	15(b)(d)
			Combined(c)	22
SO_2	Gas	Good combustion	29(d)	57(a)(d)
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	53(d)	53(b)(d)
			Combined(c)	81
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		
H_2SO_4 Mist	Gas	Good combustion	3(d)	6(a)(d)
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	6(d)	6(b)(d)
			Combined(c)	9
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		

*These values will be calculated using F factors.
(a) Based on a maximum of 3900 hours of operation with natural gas firing.
(b) Based on a maximum of 2000 hours of operation with fuel oil firing.
(c) Based on 1900 hours natural gas firing and 2000 hours of operation with fuel oil firing.
(d) Compliance shall be demonstrated through fuel sulfur analysis.

Monitoring

The BACT emission limitations for NO_x are one-hour averages. Compliance with these standards will be verified by a stack test and excess emissions will be monitored by a stack continuous emissions monitoring system (CEMS) for NO_x and oxygen. The NO_x CEMS will be

used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring which are required in 40 CFR 60, Subpart GG, and which are used as indicators of compliance with the NO_x standard specified in the subpart. Since the NO_x emission standard from Subpart GG is more than twice the BACT standard, monitoring for emissions in excess of the BACT limits using the NO_x CEMS is more stringent. FBN monitoring is not required for excess emission reports when excess emissions are reported based on the stack monitoring system. The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) will be replaced by certification tests of the NO_x and oxygen CEMS.

Details of the Analysis May be Obtained by Contacting:

Al Linero, P.E., BACT Coordinator
Department of Environmental Protection
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:	Approved by:
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Virginia B. Wetherell, Secretary Dept. of Environmental Protection
march 29, 1995 Date	April 11th, 1995 Date

Memorandum

Florida Department of Environmental Protection

To: Virginia B. Wetherell, Secretary

FROM: Howard L. Rhodes, Director
Division of Air Resources Management

Subj: Approval of Construction Permit PSD-Fl-212
Gainesville Regional Authority (GRU)

Date: March 28, 1995

Attached for your approval and signature is a permit prepared by the Bureau of Air Regulation for the above mentioned company to construct a 74MW simple cycle combustion turbine designed to burn natural gas and No. 2 fuel oil.

The control measures consist of dry low NOx burners and water injection for control of nitrogen dioxide emissions. Sulfur dioxide emissions will be controlled by the use of No. 2 fuel oil with a 0.05% sulfur content by weight.

The original intent to issue was published in the Gainesville Sun on December 24, 1994. Some modifications were made in response to comments by GRU.

This permit is not controversial. I recommend your approval and signature.

HLR/th/t

Attachment

GRU
The Utility of Choice

GAINESVILLE REGIONAL UTILITIES
Strategic Planning

December 2, 1996

Mr. Hamilton S. (Buck) Oven, Jr., Coordinator
Office of Siting Coordination
Department of Environmental Protection
2600 Blair Stone Rd., MS 48
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities (GRU)
Deerhaven Generating Station, Unit 2
Site Certification (PA 74-04)

Dear Mr. Hamilton:

In followup to GRU's June 28, 1995 correspondence and Title V permit application, enclosed are particulate emission calculations for the coal handling facilities at the above-referenced site. The emission estimates are based on the following assumptions:

(1) Weekly and annual maximum potential coal throughput rates of 12,700 and 660,400 tons, respectively, for all emission points;

(2) No controls for railcar unloading (CH-001), belt conveyor 2 to belt conveyor 3A transfer point (CH-002), belt conveyor 2 to belt conveyor 3B transfer point (CH-003), belt conveyor 3A to storage pile transfer point (CH-004), and belt conveyor 3B to storage pile transfer point (CH-005);

(3) Enclosure control efficiency of 70% for transfer points located within the crusher building (CH-010A - CH-010D) and coal bunker building (CH-011A, CH-011B); and

(4) Insignificant emissions from covered conveyor belts.

Mr. Hamilton S. "Buck" Oven, Jr., Coordinator
December 2, 1996
Page 2

These calculations show that emissions from these sources are well below those estimated and modeled in the Site Certification application (Section 5.6, pg. 5-51). Furthermore, visual emission observations conducted by GRU and the Department demonstrated that the 20% opacity standard can be met under the conditions presented above.

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

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: R. Casserleigh
F. Hancock
A. Morrison, HGSS
A2.2

dhcoal.y19

Deerhaven Station – Summary of Coal Handling Sources

Source Description	Emission Point ID	Emission Type[1]	PM/PM_{10} Emission Rates (lb/wk)	(ton/yr)
Coal Handling – Railcar Unloading; Bottom Discharge	CH–001	F	11.840	0.310
Coal Handling – Belt Conveyor 2 to Belt Conveyor 3A	CH–002	F	11.840	0.310
Coal Handling – Belt Conveyor 2 to Belt Conveyor 3B	CH–003	F	11.840	0.310
Coal Handling – Belt Conveyor 3A to Storage Pile	CH–004	F	11.840	0.310
Coal Handling – Belt Conveyor 3B to Storage Pile	CH–005	F	11.840	0.310
Coal Storage – Conveyor 3A to Ready Storage Pile	CH–006	F	10.147	0.025
Coal Storage – Conveyor 3B to Episodic Storage Pile	CH–007	F	10.147	0.025
Coal Storage – Main Storage Pile	CH–008	F	178.080	0.447
Coal Handling – Dozer Operations on Storage Pile	CH–009	F	137.933	3.301
Coal Handling – Crusher Building; Belt Conveyor 4A to Surge Bin	CH–010A	F	3.550	0.090
Coal Handling – Crusher Building; Surge Bin to Crusher Feeder	CH–010B	F	3.550	0.090
Coal Handling – Crusher Building; Crusher Feeder to Crusher	CH–010C	F	3.550	0.090
Coal Handling – Crusher Building; Crusher to Belt Conveyor 5A	CH–010D	F	3.550	0.090
Coal Handling – Coal Bunker Building; Belt Conveyor 5A to Belt Conveyor 6A	CH–011A	F	3.550	0.090
Coal Handling – Coal Bunker Building; Belt Conveyor 6A to Bunkers	CH–011B	F	3.550	0.090
		Totals	**416.807**	**5.888**

[1] F = Fugitive

DHC6A.WK1

al - For File

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning

RECEIVED
JAN 19 1996
BUREAU OF AIR REGULATION

January 18, 1996

Mr. Clair Fancy, Chief
Bureau of Air Regulation
Florida Dept. of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities
Deerhaven Generating Station, Combustion Turbine No. 3
PSD-FL-212, PA 74-04D
Ambient Effects Curves - Clarification

Dear Mr. Fancy:

By letter dated November 27, 1995 GRU submitted ambient effects curves for the above-referenced unit. Please note that certain curves, specifically the Estimated Performance curve and the Temperature Effects curve, upon which the text (and the example calculations) were based had been updated; the corresponding text had not. Therefore, there was an inconsistency between the text (e.g., ISO Output) and the curves that may have caused some confusion. Provided herein is the revised text which conforms to the curves applicable to this unit.

Please call me at (904) 334-3400 Ext. 1284 if you have any questions.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

cc: EPA
NPS

xc: D. Beck
R. Casserleigh
C. Kirts, FDEP-Jax.
B. Oven, FDEP- Tall.
DHGT3

CT3curv2.y17

PERFORMANCE ESTIMATING

A. General

The performance data presented in this section is in the form of curves which may be utilized in estimating and evaluating the affects of compressor inlet temperature on turbine output, heat rate, and air flow. The curves are for the base load operation mode of the gas turbine using natural gas and distillate fuel. Since the curves are based on ISO conditions [compressor inlet temperature of 59°F (15°C) and a barometric pressure of 14.7 psia (101 kPa)], operational performance data can be derived after determining the correction factor for the particular site conditions.

B. Performance Derivation

To derive the site output of a typical MS-7001 gas turbine operating under full load in the base mode using natural gas, it is necessary to convert from ISO conditions to site conditions. This is accomplished by determining the altitude factor for the specific site location from drawing 416HA662 and determining the temperature percent factor from drawing 522HA283 Rev-1.

For example, to determine the full load output and heat rate under base mode conditions at a site altitude of 400 feet (122 m) and a compressor inlet temperature of 100°F (38°C), convert ISO conditions to actual site conditions.

Full Load Site Output = Output (ISO) × Altitude Correction Factor (ACF)
× Temperature Correction Factor (TCF)

Full Load Site Heat Rate = Heat Rate (ISO) × Temperature Correction Factor (TCF)

Where: for natural gas firing

ISO Output = 84.96 megawatts

ISO Heat Rate = 10,440 Btu/kwhr

ACF = 0.986 [from drawing 416HA662 for 400 feet (122 m) altitude]

TCF (Output) = 0.86 [from drawing 522HA283 for 100°F (38°C)]

TCF (Heat Rate) = 1.03 [from drawing 522HA283 for 100°F (38°C)]

Therefore:

Full Load Site Output = 84.96 x 0.986 x 0.86 = 72.04 megawatts

Full Load Site Heat Rate = 10,440 x 1.03 = 10,753 Btu/kwhr

To determine part load heat rate under base mode conditions at the same altitude and temperature, calculate as follows:

Percent Full Load Output (at the site conditions) =
Part Load Output/Full Load Output × 100 Percent

General Electric Model PG7121(EA) Gas Turbine

Estimated Performance - Configuration: DLN Combustor

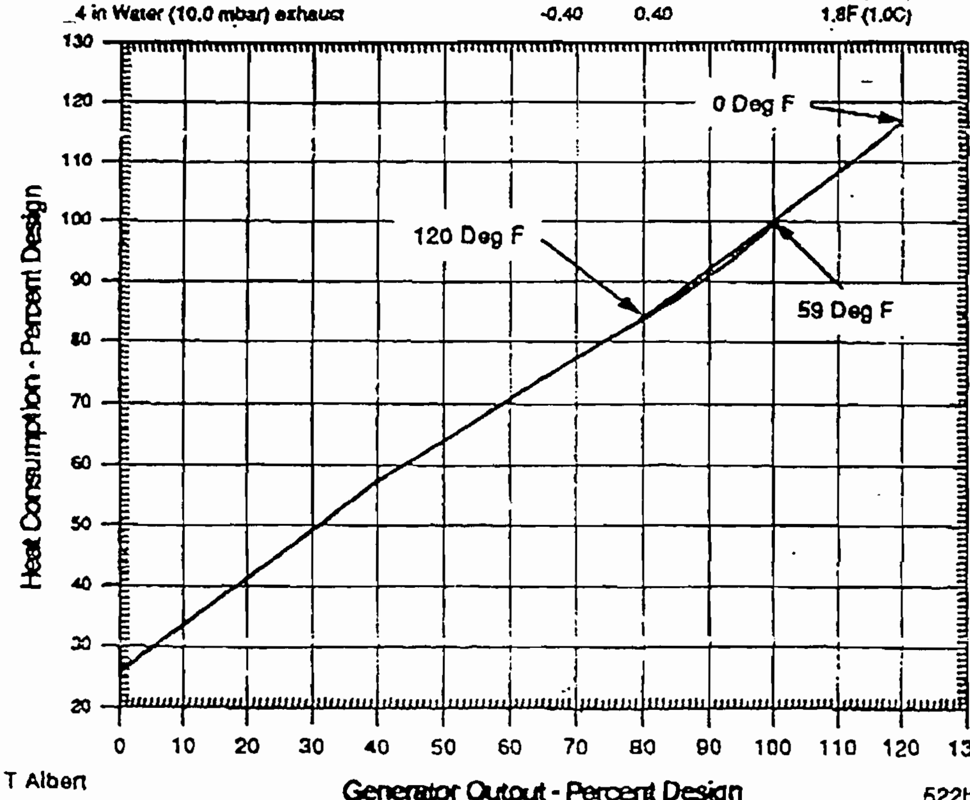
Compressor Inlet Conditions 59F (15 C), 60% Relative Humidity
Atmospheric Pressure 14.7 psia (1.013 bar)

			Natural Gas	Distillate Oil
Fuel			Natural Gas	Distillate Oil
Design Output	kW		84960	83500
Design Heat Rate (LHV)	Btu/kWh	(kJ/kWh)	10440 (11010)	10520 (11100)
Design Heat Cons (LHV)	Btu/h	(kJ/h) x10^6	887.0 (935.6)	878.4 (926.0)
Design Exhaust Flow	lb/h	(kg/h) x10^3	2359 (1070)	2365 (1073)
Exhaust Temperature	deg. F	(deg.C)	999 (537)	999 (537)
Load			Base	Base

Notes:

1. Altitude correction on curve 416HA662 Rev A.
2. Ambient temperature correction on curve 522HA283 Rev 1.
3. Effect of modulating IGV's on exhaust temperature and flow on curve 522HA284 Rev 1.
4. Humidity effects on curve 498HA697 Rev B - all performance calculated with a constant specific humidity of .0064 or less so as not to exceed 100% relative humidity.
5. Plant Performance is measured at the generator terminals and includes allowances for excitation power, shaft driven auxiliaries, and 4.0 in H2O (10.0 mbar) inlet and 5.5 in H2O (13.7 mbar) exhaust pressure drops, a DLN Combustor, and the effects of inlet bleed heating.
6. Additional inlet and exhaust pressure loss effects:

	% Effect on Output	Heat Rate	Effect on Exhaust Temp.
4 in Water (10.0 mbar) inlet	-1.40	0.42	1.9F (1.0C)
4 in Water (10.0 mbar) exhaust	-0.40	0.40	1.8F (1.0C)



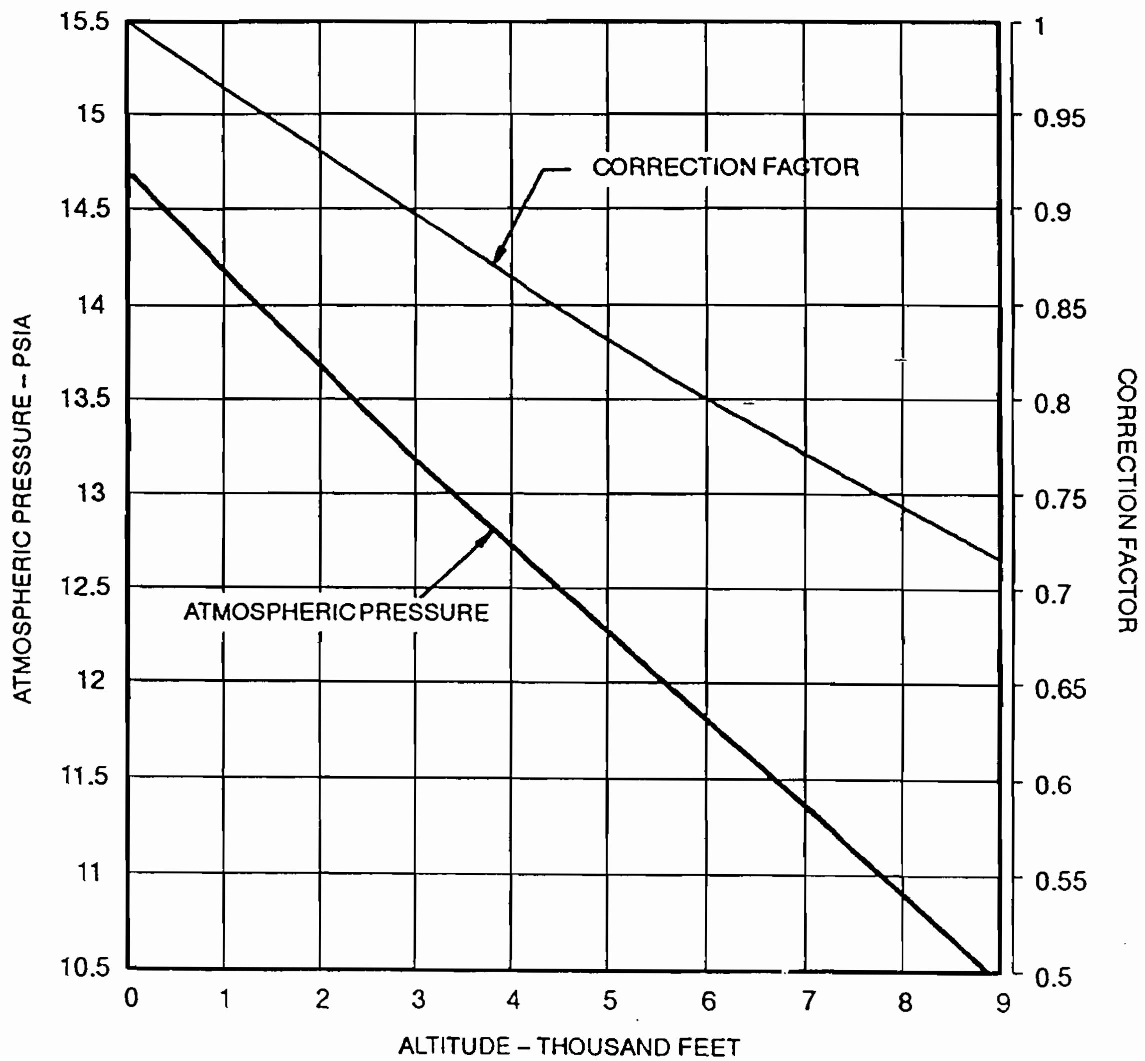
T Albert
7/12/95

522HA282
Rev - 1

General Electric Gas Turbine
Altitude Correction Factor

Altitude Vs Atmospheric Pressure
And
Altitude Vs Correction Factor
For Gas Turbine Output And Fuel Consumption

NOTES:
1. Heat Rate and Thermal Efficiency are not affected by altitude.
2. Correction Factor = P(atm)/14.7



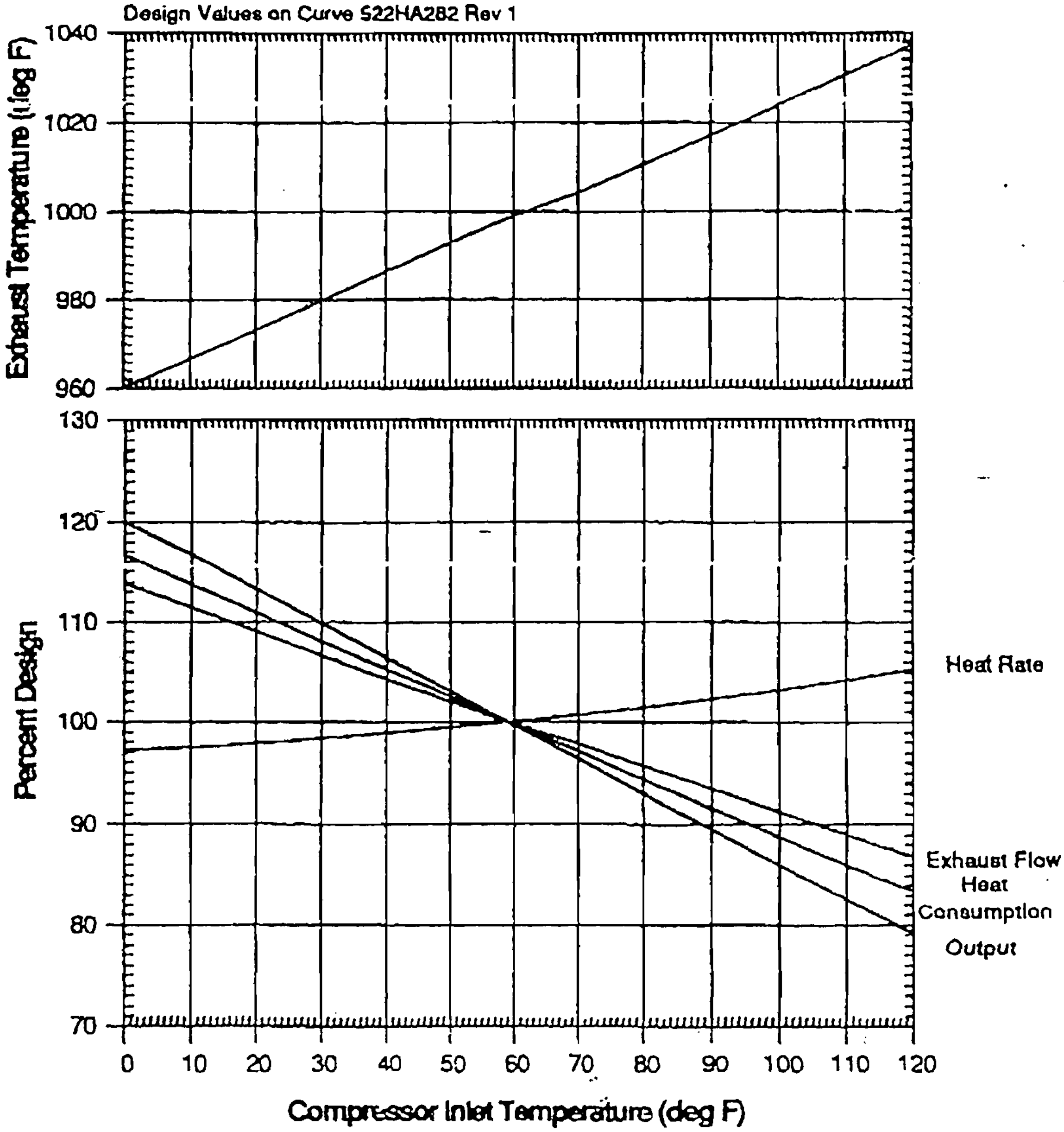
4/24/90
F.J. BROOKS

416HA662
REV A

GENERAL ELECTRIC MODEL PG7121(EA) GAS TURBINE

Effect of Compressor Inlet Temperature on Output, Heat Rate, Heat Consumption, Exhaust Flow And Exhaust Temperature at Base Load

Configuration: DLN Combustor
Fuel: Natural Gas, Distillate Oil
Design Values on Curve 522HA282 Rev 1



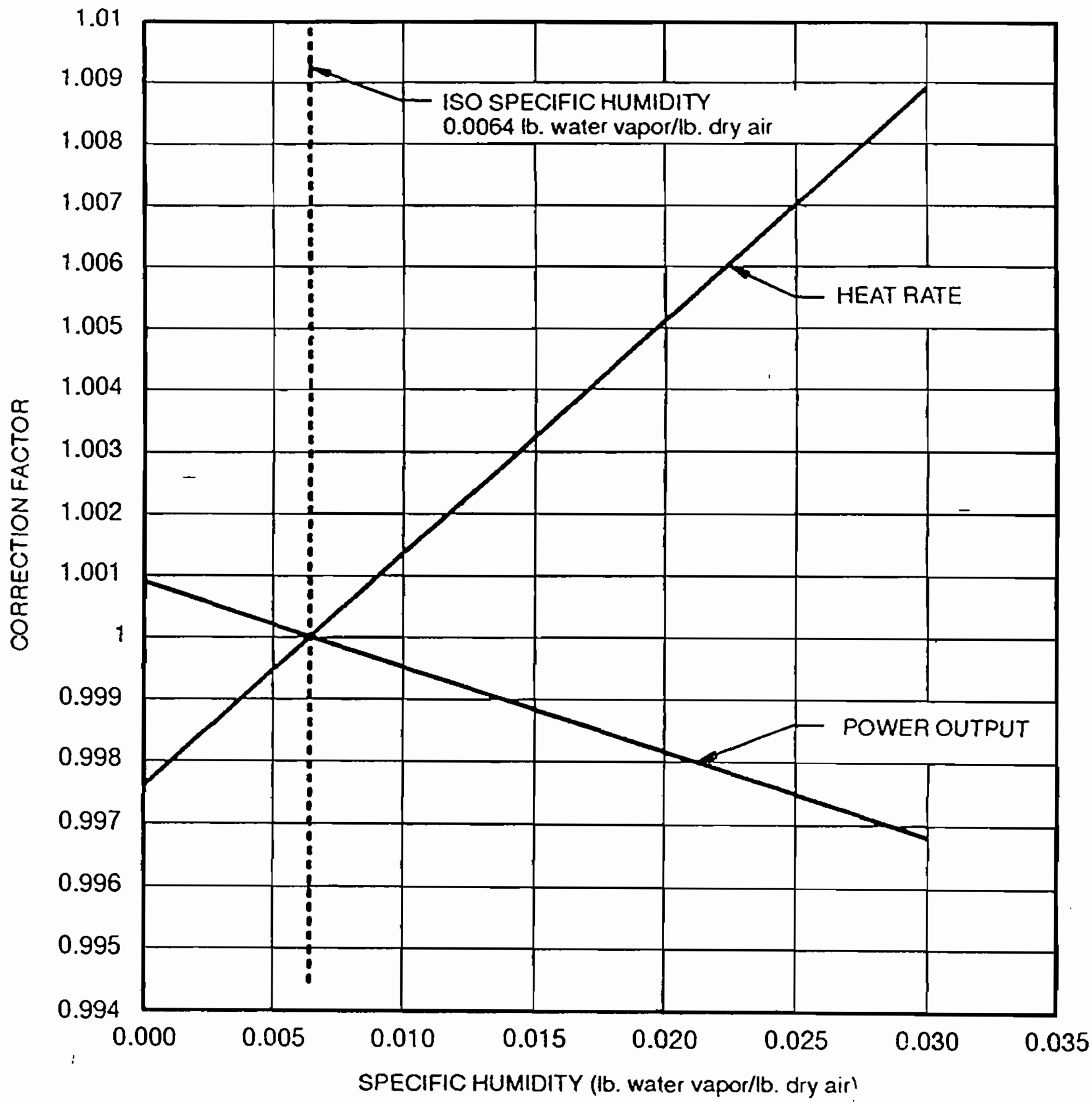
T Albert
7/13/95

522HA283
Rev - 1

General Electric MS6001, MS7001 And MS9001 Gas Turbines

Corrections To Output And Heat Rate
For Non–Iso Specific Humidity Conditions

For Operation At Base Load On Exhaust
Temperature Control Curve



10/10/89
DA JAQUEWAY

498HA697
REV B

ae

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning

December 22, 1995

RECEIVED
JAN 02 1996
BUREAU OF
AIR REGULATION

Mr. Clair Fancy, Chief
Bureau of Air Regulation
Department of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities
Deerhaven Generating Station
Combustion Turbine No. 3 (PSD-FL-212, PA 74-04D)
Notice of Startup

Dear Mr. Fancy:

In accordance with 40 CFR 60.7(a)(3) notice is hereby provided that the startup date of the above-referenced unit was December 20, 1995.

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

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: D. Beck
R. Casserleigh
C. Kirts, FDEP-Jax.
B. Oven, FDEP-Tall.
DHGT3

ct3star.y17

(904) 334-3400 ext. 1261 P.O. Box 147117, Station A136, Gainesville, Florida 32614-7117 Fax: (904) 334-3151

GRU
GAINESVILLE REGIONAL UTILITIES
Strategic Planning

November 27, 1995

RECEIVED
DEC 4 1995
BUREAU OF
AIR REGULATION

Mr. Clair Fancy, Chief
Bureau of Air Regulation
Florida Dept. of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities
Deerhaven Generating Station, Combustion Turbine No. 3
PSD-FL-212, PA 74-04D
Ambient Effects Curves

Dear Mr. Fancy:

Pursuant to the above-referenced permits, enclosed are the ambient effects curves for Deerhaven Combustion Turbine No. 3. This unit is currently projected to startup in early December and to be performance-tested in January or February 1996.

Please call me at (904) 334-3400 Ext. 1284 if you have any questions.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: D. Beck
R. Casserleigh
C. Kirts, FDEP-Jax.
B. Oven, FDEP- Tall.
DHGT3

CT3curve.y17

(904) 334-3400 ext. 1261 P.O. Box 147117, Station A136, Gainesville, Florida 32614-7117 Fax: (904) 334-3151

PERFORMANCE ESTIMATING

A. General

The performance data presented in this section is in the form of curves which may be utilized in estimating and evaluating the affects of compressor inlet temperature on turbine output, heat rate, and air flow. The curves are for the base load operation mode of the gas turbine using natural gas and distillate fuel. Since the curves are based on ISO conditions [compressor inlet temperature of 59°F (15°C) and a barometric pressure of 14.7 psia (101 kPa)], operational performance data can be derived after determining the correction factor for the particular site conditions.

B. Performance Derivation

To derive the site output of a typical MS–7001 gas turbine operating under full load in the base mode using natural gas, it is necessary to convert from ISO conditions to site conditions. This is accomplished by determining the altitude factor for the specific site location from drawing 416HA662 and determining the temperature percent factor from drawing 499HA734.

For example, to determine the full load output and heat rate under base mode conditions at a site altitude of 400 feet (122 m) and a compressor inlet temperature of 100°F (38°C), convert ISO conditions to actual site conditions.

Full Load Site Output = Output (ISO) × Altitude Correction Factor (ACF)
× Temperature Correction Factor (TCF)

Full Load Site Heat Rate = Heat Rate (ISO) × Temperature Correction Factor (TCF)

Where:

ISO Output = 83.5 megawatts

ISO Heat Rate = 10,480 Btu/kwhr

ACF = 0.986 [from drawing 416HA662 for 400 feet (122 m) altitude]

TCF (Output) = 0.845 [from drawing 499HA734 for 100°F (38°C)]

TCF (Heat Rate) = 1.045 [from drawing 499HA734 for 100°F (38°C)]

Therefore:

Full Load Site Output = 83.5 × 0.986 × 0.845 = 69.57 megawatts

Full Load Site Heat Rate = 10,480 × 1.045 = 10,952 Btu/kwhr

To determine part load heat rate under base mode conditions at the same altitude and temperature, calculate as follows:

Percent Full Load Output (at the site conditions) =
Part Load Output/Full Load Output × 100 Percent

General Electric Model PG7121(EA) Gas Turbine

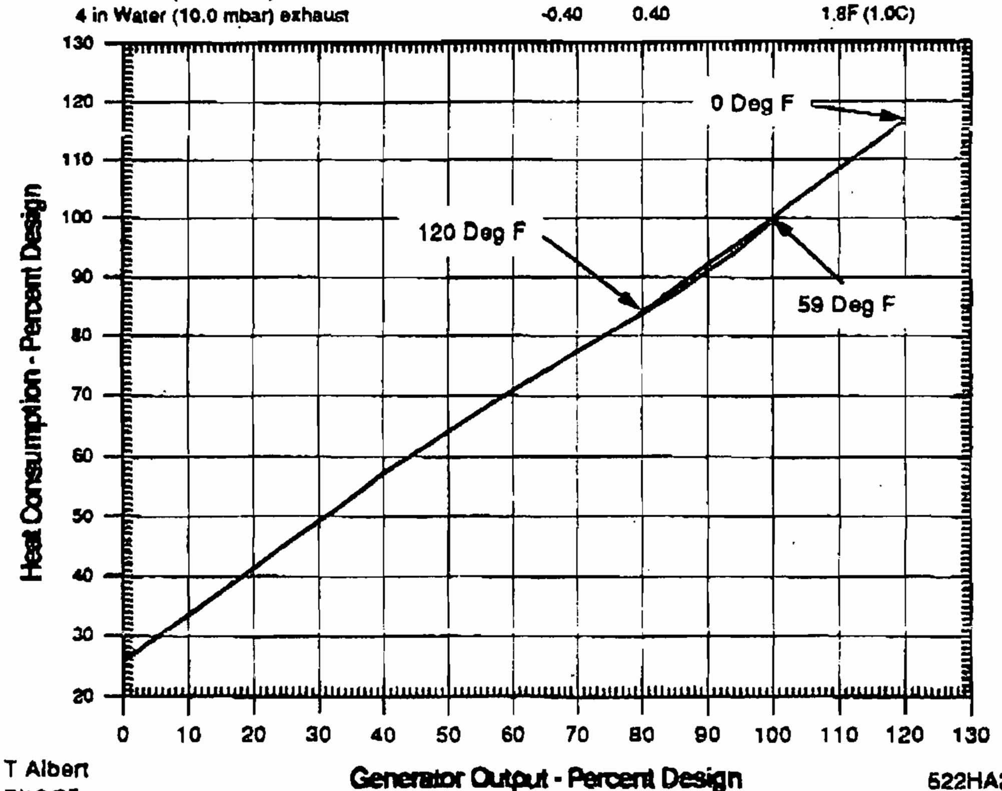
Estimated Performance - Configuration: DLN Combustor

Compressor Inlet Conditions 59F (15 C), 60% Relative Humidity
Atmospheric Pressure 14.7 psia (1.013 bar)

Fuel			Natural Gas	Distillate Oil
Design Output	kW		84960	83500
Design Heat Rate (LHV)	Btu/kWh	(kJ/kWh)	10440 (11010)	10520 (11100)
Design Heat Cons (LHV)	Btu/h	(kJ/h) x10^6	887.0 (935.6)	878.4 (926.0)
Design Exhaust Flow	lb/h	(kg/h) x10^3	2359 (1070)	2365 (1073)
Exhaust Temperature	deg. F	(deg.C)	999 (537)	999 (537)
Load			Base	Base

Notes:
1. Altitude correction on curve 416HA662 Rev A.
2. Ambient temperature correction on curve 522HA283 Rev 1.
3. Effect of modulating IGV's on exhaust temperature and flow on curve 522HA284 Rev 1.
4. Humidity effects on curve 498HA697 Rev B - all performance calculated with a constant specific humidity of .0064 or less so as not to exceed 100% relative humidity.
5. Plant Performance is measured at the generator terminals and includes allowances for excitation power, shaft driven auxiliaries, and 4.0 in H2O (10.0 mbar) inlet and 5.5 in H2O (13.7 mbar) exhaust pressure drops, a DLN Combustor, and the effects of inlet bleed heating.
6. Additional inlet and exhaust pressure loss effects:

	% Effect on Output	% Effect on Heat Rate	Effect on Exhaust Temp.
4 in Water (10.0 mbar) inlet	-1.40	0.42	1.9F (1.0C)
4 in Water (10.0 mbar) exhaust	-0.40	0.40	1.8F (1.0C)



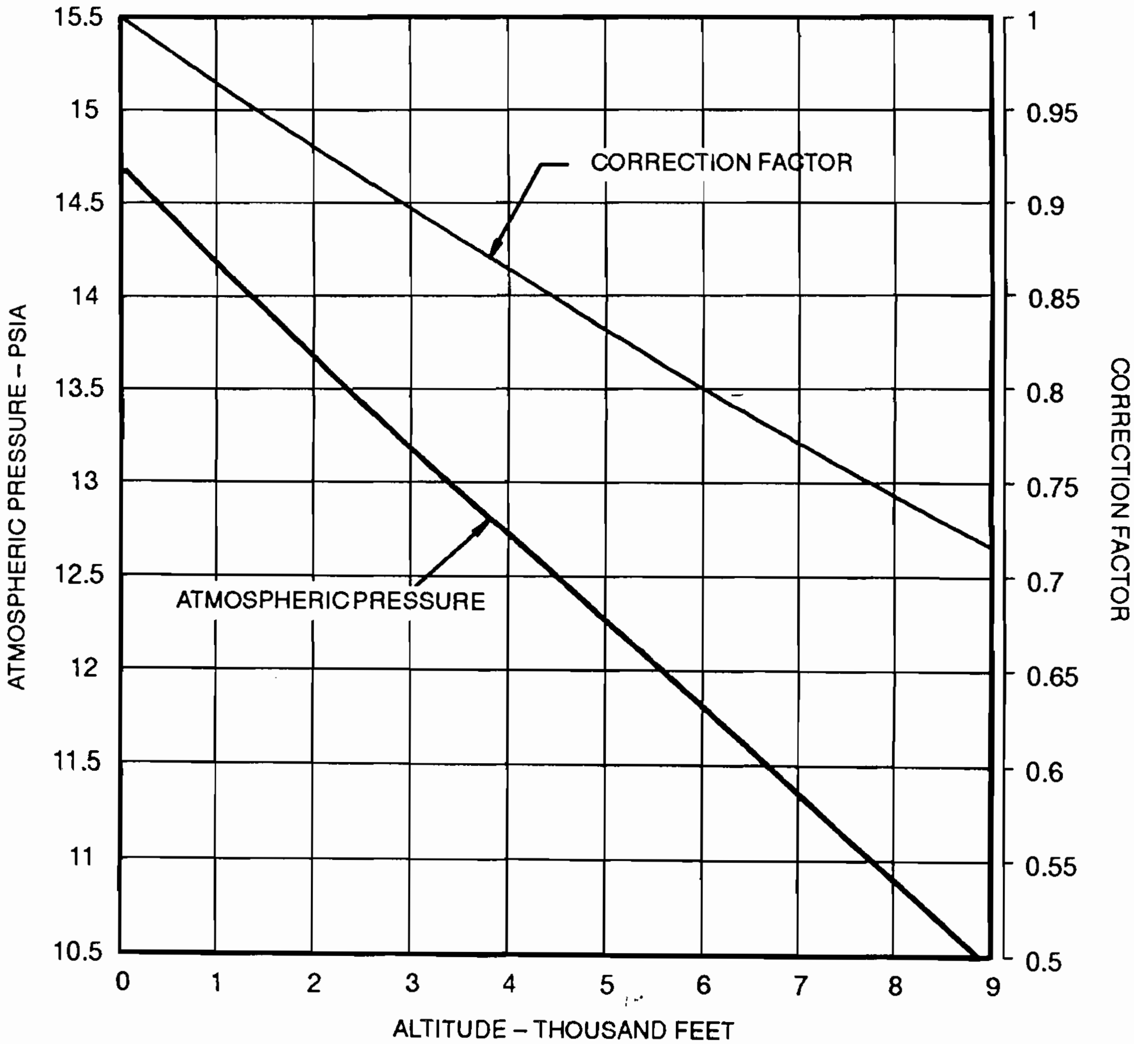
T Albert
7/12/95

522HA282
Rev - 1

General Electric Gas Turbine
Altitude Correction Factor

Altitude Vs Atmospheric Pressure
And
Altitude Vs Correction Factor
For Gas Turbine Output And Fuel Consumption

NOTES:
1. Heat Rate and Thermal Efficiency are not affected by altitude.
2. Correction Factor = P(atm)/14.7



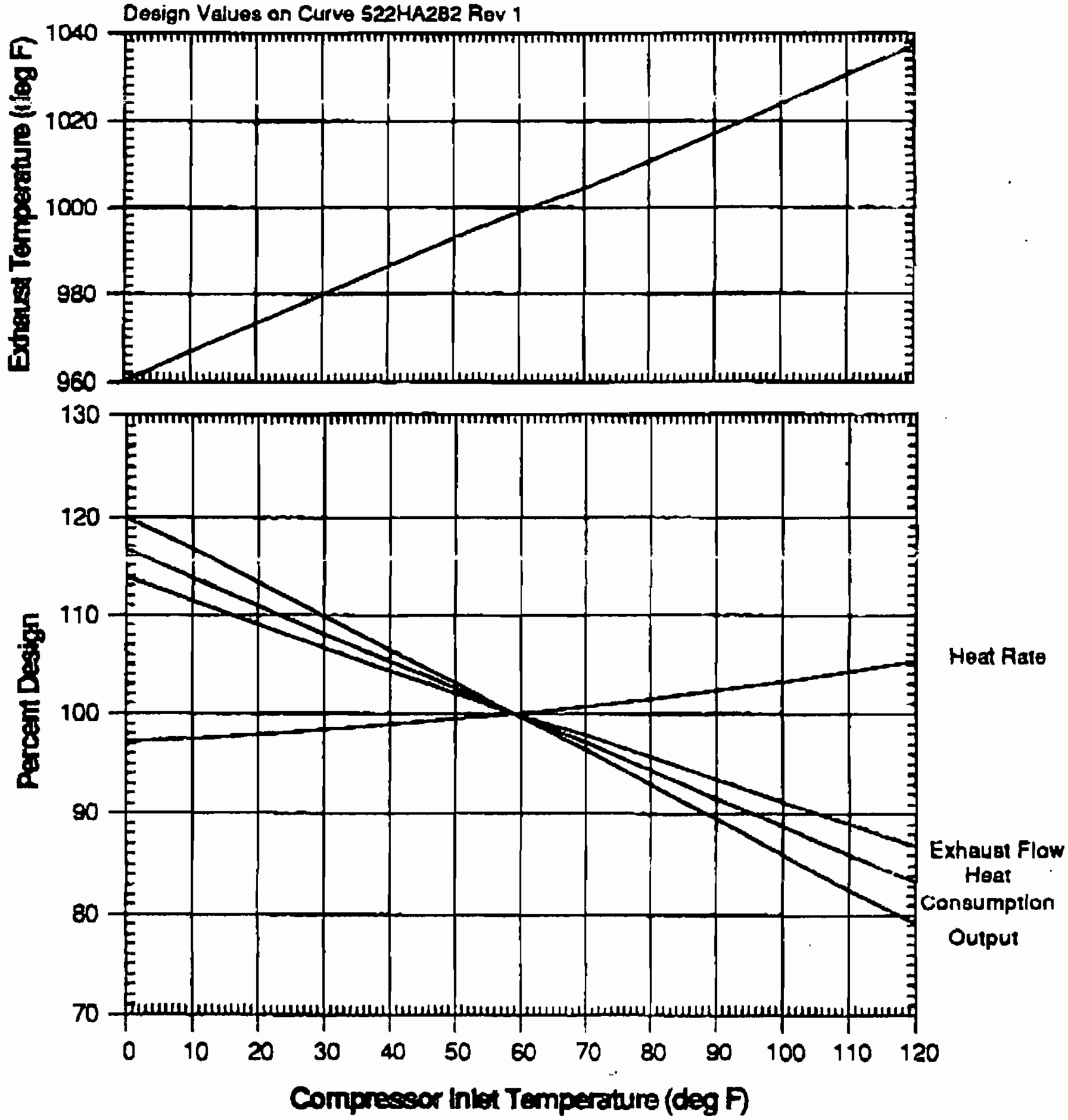
4/24/90
F.J. BROOKS

416HA662
REV A

GENERAL ELECTRIC MODEL PG7121(EA) GAS TURBINE

Effect of Compressor Inlet Temperature on Output, Heat Rate, Heat Consumption, Exhaust Flow And Exhaust Temperature at Base Load

Configuration: DLN Combustor
Fuel: Natural Gas, Distillate Oil
Design Values on Curve 522HA282 Rev 1



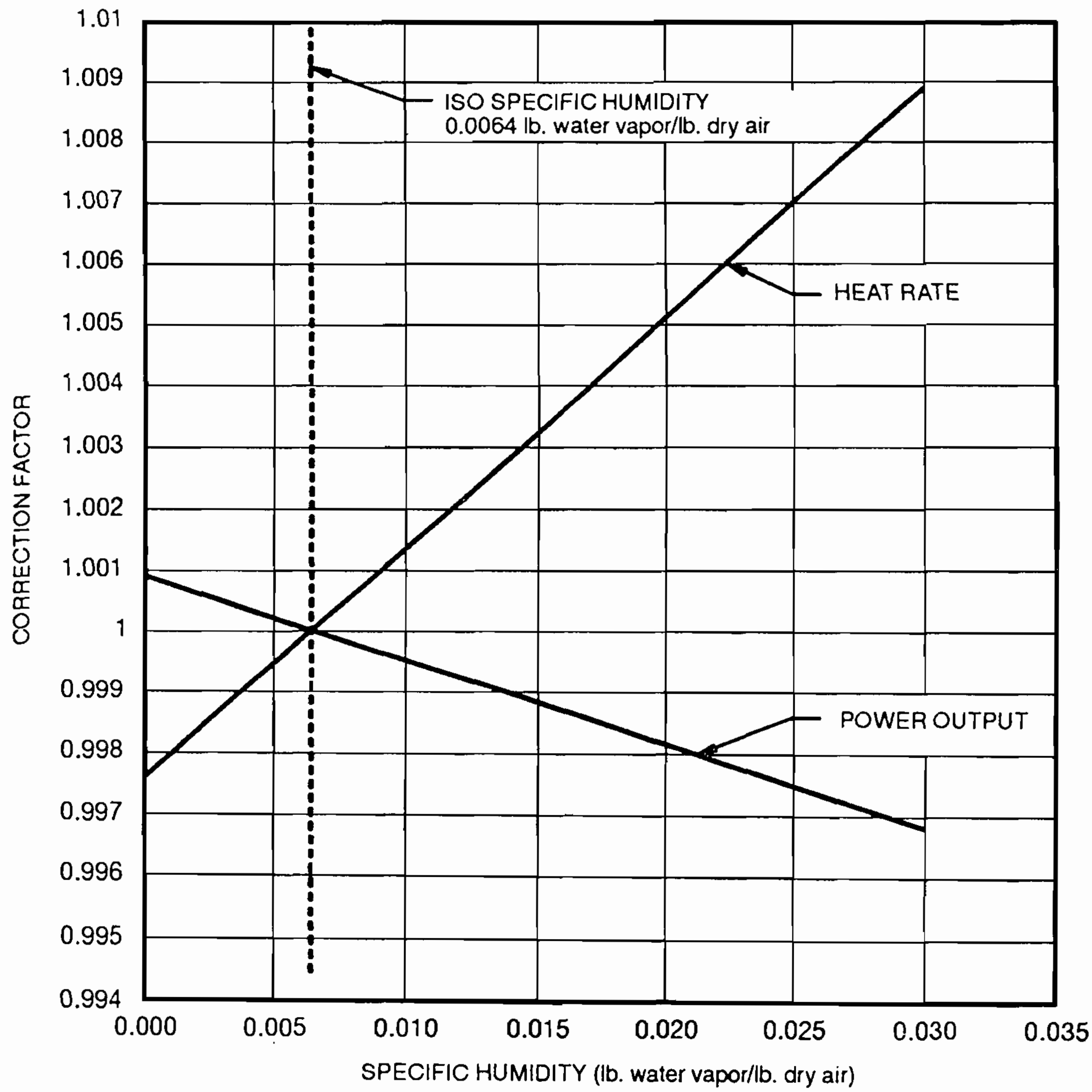
T Albert
7/13/95

522HA283
Rev - 1

General Electric MS6001, MS7001 And MS9001 Gas Turbines

Corrections To Output And Heat Rate
For Non–Iso Specific Humidity Conditions

For Operation At Base Load On Exhaust
Temperature Control Curve



10/10/89
DA JAQUEWAY

498HA697
REV B

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning

June 28, 1995

DEPARTMENT OF ENVIRONMENTAL PROTECTION

JUN 30 1995

SITING COORDINATION

Mr. Hamilton S. (Buck) Oven, Jr., Coordinator
Office of Siting Coordination
Department of Environmental Protection
2600 Blair Stone Road, MS 48
Tallahassee, FL 32399-2400

Received by BAR on 10/31/95 aa

Re: Gainesville Regional Utilities
Deerhaven Unit No. 2
Site Certification No. PA 74-04

Dear Mr. Oven:

Gainesville Regional Utilities' (GRU) Deerhaven Unit No. 2 was certified in May of 1978. While our records do not indicate that the use of particulate matter control devices is required by the Department for Unit No. 2's coal handling facilities, certain control devices were installed when the unit was originally constructed to help minimize fugitive emissions. Recent visible emissions testing indicates, however, that these pollution control devices are not necessary to meet the 20 percent opacity limit established in the conditions of certification.

Like other sources throughout the State, GRU is currently in the process of completing its Title V air operation permit application, and would like confirmation from the Department that these particulate matter control devices are not necessary. Pursuant to Special Condition I.A.5.b., the Department has the authority to determine whether certain control devices are adequate to comply with the visible emission limit of 20 percent opacity, and GRU can demonstrate that no pollution control equipment is necessary for compliance with the opacity limit.

Using approved methods, GRU recently conducted visible emissions testing on its coal handling facilities for Unit No. 2. The particulate matter control devices were not operating during these recent tests. The results indicate that the 20 percent opacity limit can be met without the use of any particulate matter control devices. A copy of the test results is enclosed for your review and information. While there are some fugitive particulate matter emissions from the coal conveyance, storage, transfer, and processing facilities, the test results indicate that the visible emissions ranged from zero to just over four percent opacity--much below the 20 percent standard.

(904) 334-3400 ext. 1261 P.O. Box 147117, Station A136, Gainesville, Florida 32614-7117 Fax: (904) 334-3151

Again, GRU would like confirmation from the Department that particulate matter control devices are not required for Unit No. 2's coal handling facilities since the opacity standard can be met without the use of such devices. After you have had an opportunity to review this information, please let us know if you have any questions or concerns. We would be happy to meet with you to discuss this matter in greater detail.

Your continued cooperation and assistance are very much appreciated.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

Enclosure

xc: Randy Casserleigh
Fred Hancock
Angela Morrison, HGSS
A2.2

W:\U0070\ENV\SITECERT.DH2

Cubix Corporation

FLORIDA OFFICE
2106 NW 67th Place, #7
Gainesville, Florida 32653
904-378-0332 TEL
904-378-0354 FAX

CORPORATE HEADQUARTERS
9225 Lockhart Highway
Austin, Texas 78747
512-243-0202 TEL
512-243-0222 FAX

May 23, 1995

Ms. Yolanta Jonynas
Gainesville Regional Utilities
P.O. Box 147117
Gainesville, Florida

Dear Ms. Jonynas

Visual emission testing was conducted at the Deerhaven Station for Gainesville Regional Utilities (GRU) on April 27th and 30th, 1995. The testing followed the procedures of 40 CFR 60, Appendix A, Method 9; an observer, certified within the state of Florida, performed the opacity readings. The purpose of these tests was to determine the opacity of fugitive emissions from the coal handling process at this facility. Cubix Corporation, Florida Office performed the testing.

The Deerhaven Station is a power plant at which two coal-fired boilers are used to generate electrical power; this power is then sold to residents and businesses located within the city of Gainesville, Florida. In order to operate these boilers, coal is transported to the facility via rail-car, stacked into a pile for reserve usage, transported to a crusher, and then transported to set of coal bunkers. The coal is injected into the boilers directly from the bunkers.

The Visual Emissions Summary contains the results of the testing. Each test was one hour in duration with readings taken every 15 seconds. A total of four sources were monitored with one test run performed on each source. Within the summary table, the highest average refers to the average opacity emissions from 24 contiguous readings. Operational and process data was collected and supplied by GRU personnel.

All other data relevant to this testing is contained in the Appendix of this report. Contained within the Appendix are field data sheets, operational data, and the observer certifications. Cubix collected and reported the enclosed test data in accordance with the procedures described in EPA Method 9. Cubix makes no warranty as to the suitability of the test methods. Cubix assumes no liability relating to the interpretation and use of the test data.

Sincerely,

Leonard Brenner

Visual Emissions Summary

Source Desciption	Process Operation	Maximum Opacity (%)	Minimum Opacity (%)	Highest 24 Ave. Opacity (%)
Primary Crusher Baghouse	300 tons/hr	10	0	1.25
Coal Bunkering Baghouse	300 tons/hr	0	0	0
Tower Chute Coal Piling	1467 tons/hr	25	0	4.38
Rail-Car House Unloading	15 cars/hr	5	0	0.42

April 27th & 30th, 1995
Gainesville Regional Utilities
Deerhaven Station
Alachua County, Florida

V.E. observer: Leonard Brenner
Test Run Duration: 60 minutes
Total Readings per Run: 240 readings

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning

October 2, 1995

RECEIVED

OCT 5 1995

Bureau of
Air Regulation

Mr. Clair Fancy, Chief
Bureau of Air Regulation
Florida Dept. of Environmental Protection
2600 Blair Stone Rd.
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities
Deerhaven Generating Station
Combustion Turbine No. 3
PSD-FL-212, PA 74-04D
Startup Notification

Dear Mr. Fancy:

In accordance with 40 CFR 60.7(a)(2) notice is hereby provided that the planned startup date of the above-referenced unit is November 9, 1995. Notice of the actual startup date will be provided within 15 days of such date.

Please call me at (904) 334-3400 Ext. 1284 if you have any questions.

Sincerely,

Yolanta E. Jonynas/gm

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: D. Beck
R. Casserleigh
C. Kirts, FDEP-Jax.
B. Oven, FDEP- Tall.
DHGT3

CT3FANCY.Y17

(904) 334-3400 ext. 1261 P.O. Box 147117, Station A136, Gainesville, Florida 32614-7117 Fax: (904) 334-3151

ot

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning

RECEIVED

JUN 7 1995

Bureau of
Air Regulation

VIA TELEFAX

May 31, 1995

Mr. Clair Fancy, Chief
Florida Dept. of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Rd.
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities
Deerhaven Combustion Turbine No. 3 (PSD-FL-212)
Notification of Construction Start

Dear Mr. Fancy:

Please be advised that construction activities related to the above-referenced unit commenced on May 1, 1995. If you have any questions, please call me at (904) 334-3400 Ext. 1284.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: Doug Beck
Chris Kirts, FDEP-JAX
Buck Oven, FDEP-TALL
DHGT3

ct3start.y16

OGC FILE CLOSING FORM

Deputy General Counsel Bill Congdon

Attorney Jeff Braswell Date 6/01/95

OGC File # 95-0005 Case Style

Gainesville Regional Utilities (Deerhaven Combustion Turbine No. 3) v. DEP

The above-referenced OGC file is being closed and sent to archives for storage. See below for summary of final disposition.

ENFORCEMENT CASE

___ Draft Consent Order received, case resolved informally.

___ Consent Order executed, all conditions met.

___ Draft Notice of Violation received, case resolved informally.

___ Notice of Violation issued, Final Order filed, all conditions met.

___ Circuit Court action, document processed, all conditions met.

___ Other (please specify) ___

PERMITTING CASE: Permit Application # PSD-FL-212

Final Permit Status: ✓ Issued ___ Denied ___ Withdrawn
Date: 4/11/95

✓ Request for Extension of Time - No Petition was Filed.

___ Request for Extension of Time - Petition Filed.
Final Order Filed (date) ___

___ Petition for Hearing Filed.
Final Order Filed (date) ___

___ Appellate Court action, document processed, all conditions met.

✓ Other (please specify) Related OGC case # 93-4204: Final Order was issued 4/07/95.

OTHER CASES (RULEMAKING, PERSONNEL, ETC.)

Final Disposition ___

cc: District Manager Vivian Garfein
Clair Fancy, Chief, BAR

March 1990

BEST AVAILABLE COPY

Department of Environmental Regulation

Routing and Transmittal Slip

To: (Name, Office, Location)

1. Clair Fancy
2. Air Regulations
3. Magnolia Bldg
4. MS 5500

Remarks:

~~Patty~~

~~CF~~

I believe the PSD is already issued, if not it needs to be

The PSD permit was issued 4/11 please give to Teresa FYI then to Ramana [illegible] thanks Patty

1 ~~Teresa~~

2 K.nami

RECEIVED

APR 10 1995

Bureau of
Air Regulation

From	Date 4/7/95
Perry	Phone 1-9642

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

IN RE: SITE CERTIFICATION)
DEERHAVEN GENERATING STATION)
GAINESVILLE REGIONAL UTILITIES) CERTIFICATION NO. PA 74-04D
ALACHUA COUNTY, FLORIDA / OGC NO. 93-4204

FINAL ORDER MODIFYING
CONDITIONS OF CERTIFICATION

On May 16, 1978, the Siting Board, issued a final order approving certification for the Gainesville Regional Utilities Deerhaven Generating Station. That certification order approved the construction and operation of a coal fired, steam-electric generating facility and associated facilities to be located in Alachua County, Florida.

On March 22, 1994, Gainesville Regional Utilities (GRU) filed requests to modify the conditions of certification pursuant to Section 403.516(1)(b), Florida Statutes (F.S.). The GRU requested that the conditions be modified to approve the construction and operation on site of a 74 megawatt (nominal) combustion turbine burning either natural gas or distillate fuel oil.

On April 2, 1994, notice of the proposed modification was published in the Gainesville Sun. On December 23, 1994, Notice of Intent to Issue Proposed Modification of Power Plant Certification was published in the Florida Administrative Weekly. On December 21, 1994, all of the parties to the original proceeding were mailed copies of the petition to modify. The notices specified that a hearing would be held if a party to the original certification hearing objects within 45 days from receipt of the proposed notice of modification or if a person whose substantial interests will be affected by the proposed modification objects in writing within 30 days after issuance of the public notice. No timely written objection to the proposed modifications was received by the Department.

One of the persons who was mailed a copy of the Department's Notice of Intent to Issue was Mr. Dan Hargrove of Gainesville. Previously, by letter dated August 24, 1994, Mr. Hargrove had expressed his objection to the modification requested by GRU. Mr. Hargrove, who had not been a party to the original certification proceeding, objected to the proposed increase in generating capacity on the grounds that GRU had failed to live up to a stipulation entered into in 1978 between GRU and that Gainesville Chapter of the Sierra Club.

On January 19, 1995 the Department mailed Mr. Hargrove a copy of the Notice of Intent to Issue. The return receipt indicates that Mr. Hargrove received the document on January 23, 1995. On February 6, 1995, the Department received a letter from Mr. Hargrove dated February 2, 1995, which was styled a written objection to the "construction of Deerhaven #3 power plant by GRU." The letter reiterated Mr. Hargrove's assertion the GRU had not lived up to its stipulation of April 5, 1978.

Mr. Hargrove's objection is not timely. Section 403.516, Florida Statutes, requires that timely written objections to a proposed modification must be filed within 30 days of public notice of the modification. Public Notice was provided by means of publication in the Florida Administrative Weekly on December 23, 1994. Consequently, the deadline for objection in this matter was January 23, 1995.

Accordingly, in the absence of any timely objection, IT IS ORDERED:

The proposed changes to the Deerhaven Generating Station described in the March 22, 1994, request for modification, are APPROVED. Pursuant to Section 403.516(l)(b), F.S., the Department hereby MODIFIES the conditions of certification for the Deerhaven Generating Station as follows:

H. Deerhaven Combustion Turbine No. 3

The construction and operation of the Gainesville Regional Utilities (GRU) Deerhaven Combustion Turbine #3 (DHCT3) shall be in accordance with all applicable provisions of Chapters 62-210 through 297 and 62-4, Florida Administrative Code (F.A.C.), and 40 CFR 60, Subpart A, Subpart GG, Appendix A and Appendix B (1993 version). The following emission limitations and conditions reflect the BACT determinations for the DHCT3. In addition to the foregoing, the project shall comply with the following conditions of certification:

General Operating Requirements

1. The maximum heat input rates, based on high heating values of each fuel, to the DHCT3 and at ISO conditions (i.e., 59° F, 60% relative humidity and 101.3 kilopascals pressure), shall not exceed 971.1 MMBTU/hr, while firing natural gas, nor 990.6 MMBTU/hr, while firing fuel oil. Heat input will vary depending on ambient conditions and the DHCT3 characteristics. Manufacturer's curves or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) at least 90 days before initial compliance testing.

2. The DHCT3 is allowed to operate up to 3900 hours per year, but not to exceed 2000 hours while firing fuel oil.

3. Only natural gas (NG) or No. 2 fuel oil shall be fired in the combustion turbine. The maximum sulfur content of the fuel oil shall not exceed 0.05 percent, by weight. GRU has established that there is approximately 55 hours of full load operation of fuel oil, which contains nominally 0.25% sulfur content, by weight, remaining in the fuel storage tank. GRU will be allowed to deplete this reserve by firing the fuel oil in the DHCT3. However, all future deliveries of fuel oil for the

DHCT3 shall meet the BACT requirement, which limits the fuel oil sulfur content to no more than 0.05%, by weight. Fuel sulfur content shall be determined and recorded each time fuel is transferred into the bulk storage tank(s).

4. 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 pursuant to Rule 62-296.310(3), F.A.C. - Unconfined Emissions of Particulate Matter.

5. Any change in the method of operation, equipment or operating hours, pursuant to Rule 62-212.200, F.A.C., Definitions- Modifications, shall be submitted to the DEP's Bureau of Air Regulation office and Northeast District office.

Emission Limits

6. The maximum allowable emissions from the DHCT3, when firing natural gas or No. 2 fuel oil, in accordance with the BACT determination, and at 95 - 100% percent load based on the manufacturer's curves submitted to the DEP, shall not exceed the following limits except during periods of start up, shutdown, and malfunction pursuant to Rule 62-210.700, F.A.C.:

MAXIMUM ALLOWABLE EMISSION LIMITS

POLLUTANT	FUEL	BACT STANDARD	LBS/HR	*TPY
NOx	Gas	15 ppmvd @ 15% Oxygen	58	113 (a)
	Oil	42 ppmvd e 15% Oxygen	184	184 (b)
			combined (c)	239
PM_{10}	Gas	Good combustion; visible emissions shall not exceed 10% opacity	7 (d)	14 (a)(d)

	Oil	Good combustion of low sulfur oil; visible emissions shall not exceed 10% opacity	combined (c)	15 (d) 15 (b)(d) 22
SO_2	Gas	Good combustion	29 (d)	57 (a)(d)
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	combined (c)	53 (d) 53 (b)(c) 81
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		
H_2SO_4 Mist	Gas	Good combustion	3 (d)	6 (a)(d)
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	combined (c)	6 (d) 6 (b)(d) 9
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		

*These values are calculated using F-factors.

(a) Based on a maximum of 3900 hours of operation with natural gas firing.

(b) Based on a maximum of 2000 hours of operation with fuel oil firing.

(c) Based on 1900 hours natural gas firing and 2000 hours fuel oil firing.

(d) Compliance shall be demonstrated through fuel sulfur analysis.

7. Visible emissions shall not exceed 10% opacity when firing natural gas or No.2 fuel oil.

8. The potential emissions projected from the DHCT3 are:

ESTIMATED POTENTIAL EMISSIONS

Pollutant	Method of Control	TPY **
CO	Good combustion, proper use of water injection system	95.2
VOC	Good combustion	8.7
Mercury	Natural Gas/No. 2 Fuel Oil	0.001
Pb	Natural Gas/No. 2 Fuel Oil	0.0638
Be	Natural Gas/No. 2 Fuel Oil	0.00033

**TPY values are for annual operation reports (AOR) and PSD applicability determinations. These values are based on the DHCT3 operating at full load at ISO for a total of 3900 hours per year, with up to 2000 hours of No.2 fuel oil-fired operation.

Compliance Determination

9. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate at which this unit will be operated, but not later than 180 days of initial operation at the maximum capability of the unit and annually thereafter, by using the following reference methods as described in 40 CFR 60, Appendix A (1993 version), and adopted by reference in Chapter 62-297, F.A.C.

Initial (I) compliance tests shall be performed on the DHCT3 while firing each fuel (gas, oil). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.340, F.A.C., on the DHCT3 with the fuel(s) used for more than 400 hours in the preceding 12-month period.

- Method 9	Visual Determination of the Opacity of Emissions from Stationary Sources (I,A)
- Method 10	Determination of Carbon Monoxide Emissions from Stationary Sources (I)
- Method 20	Determination of Nitrogen Oxides and Diluent Emissions from Stationary Gas Turbines (I,A)

Note: No other methods may be used for compliance testing unless prior DEP approval is received in writing. The DEP may request a special compliance test pursuant to Rule 62-297.340(2), 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.

10. Notwithstanding the requirements of Rule 62-297.340, F.A.C., the exclusive use of fuel oil with a maximum sulfur content limit of 0.05% or less, by weight, is the method for determining compliance for 502, H_2SO_4 mist, and PM~$_0$. There is no suitable method for the testing of PM_{10} from this type of emissions unit, and the 502 and H_2 504 emissions are clearly limited by the sulfur content of the fuel. Compliance with the 502 and sulfuric acid mist emission limits shall be determined by fuel oil analysis using ASTM D2880-71 or D4294 (or equivalent) for the sulfur content of liquid fuels and D1072-80, D303l-81, D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel. Alternatively, natural gas supplier data for sulfur content may be submitted. However, the applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. 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) (1993 version).

11. Pursuant to Rule 62-212.410, F.A.C., the permittee shall install a dry low-NOx combustor on the DHCT3 for NOx control when firing natural gas. Control of NOx when firing No. 2 fuel oil shall be accomplished by water injection.

12. An initial test for CO, concurrent with each NOx test, is required to confirm that annual potential emissions will not exceed 100 TPY. The NOx and initial CO test results shall be the average of three valid one-hour runs. The DEP's Northeast District office shall be notified, in writing, at least 30 days prior to the initial compliance tests and at least 15 days before annual compliance test(s). The combustion turbine shall operate between 95% and 100% of maximum capacity for the ambient conditions experienced during compliance test(s). The turbine manufacturer's heat input rates (based on the high heating value of the fuel) vs. ambient temperature curve shall be included with the compliance test results. The fuel feed rates and the high heating value of the fuels shall be established during the initial and annual compliance tests. Compliance test results shall be submitted to the DEP's Northeast District office no later than 45 days after completion of the last test run.

13. Excess NOx emissions from this turbine resulting from startup, shutdown, malfunction, fuel switching or load change, shall be acceptable providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the DEP's Bureau of Air Regulation or the Northeast District office for a longer duration. Best operating practices shall be documented in writing and a copy submitted to the DEP's Northeast District office along with the initial compliance test data. The document may be updated as needed with all updates submitted to the DEP's Northeast District office within thirty (30) days of implementation and shall include time limitations on excess emissions caused by turbine startup.

Notification, Reporting and Recordkeeping

14. Notification and recordkeeping shall be in accordance with 40 CFR 60.7 (1993 version). The following protocols shall be submitted to the DEP's Northeast District office for approval:

a. CEMS - If applicable, the Federal Acid Rain Program requirements of 40 CFR 75 shall apply when those requirements become effective in Florida.

b. Performance Test Protocol - At least 30 days prior to conducting the initial performance tests required by this permit, the permittee shall submit to the DEP's Northeast District office for their review and approval: a protocol outlining the procedures to be followed; the test methods; and, any differences between the reference methods and the test methods proposed to be used to verify compliance with the conditions of this permit.

c. All measurements, records, and other data required to be maintained by GRU shall be retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These data shall be made available to the DEP representatives.

Monitoring Requirements

15. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from this source. One-hour periods when NOx emissions (ppmvd @ 15% oxygen) are above the BACT standards (15/42 gas/oil) shall be reported as excess emissions following the format of 40 CFR 60.7 (1993 version). The continuous emission monitor must comply with Rule 62-297.500, F.A.C.; 40 CFR 60, Appendix F, Quality Assurance Procedures (1993 version) (or other DEP approved QA plan); 40 CFR 60, Appendix B, Performance Specification 2 (1993 version); or, if applicable,

40 CFR 75, Appendix A and Appendix B. Periods of startup, shutdown, fuel switching, malfunction, and load change shall be monitored and recorded. The NOx CEMS will be used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring, which are required in accordance with 40 CFR 60, Subpart GG (1993 version), and are used as indicators of compliance with the NOx standard specified in the subpart. Since the NOx emission standard from Subpart GG is more than twice the BACT standard, monitoring for emissions in excess of the BACT limits using the NOx CEMS is more stringent. FBN levels are not required for excess emission reports when excess emissions are reported and based on the stack monitoring system. The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) (1993 version) will be replaced by certification tests of the NOx CEMS.

16. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions and shall be prohibited pursuant to Rule 62-210.700, F.A.C.

17. The sulfur content of the fuel oil being fired in the combustion turbine shall be determined in accordance with 40 CFR 60.334(b) (1993 version). Any request for a future custom monitoring schedule shall be made in writing and directed to the DEP's Bureau of Air Regulation office. Any custom schedule approved by the DEP pursuant to 40 CFR 60.334(b) (1993 version) will be recognized as enforceable provisions of the permit, provided that the holder of this permit demonstrates that the provisions of the schedule will be adequate to assure continuous compliance. The records of natural gas and No. 2 fuel oil usage shall be kept by the company for a five-year period for regulatory agency inspection purposes.

Rule Requirements

18. The emission unit shall be in compliance with all applicable provisions of Chapter 403, Florida Statutes, and Chapters 62-4, 210, 212, 275, 296 and 297, F.A.C.

19. The emission unit shall be in compliance with all applicable requirements of 40 CFR 60, Subpart A, Appendix A and Appendix B (1993 version), Subpart GG - Standards of Performance for Stationary Gas Turbines (1993 version), and Rule 62-296.800(2) (a), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). All notifications and reports required by this specific condition shall be submitted to the DEP's Northeast District office.

20. Issuance of this certification does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (Rule 62-210.300(1), F.A.C.).

21. The emission unit shall be in compliance with all applicable provisions of Rule 62-210.650, F.A.C.: Circumvention; Rule 62-210.700, F.A.C.: Excess Emissions; Rule 62-296.800, F.A.C.: Standards of Performance for New Stationary Sources (NSPS); Chapter 62-297, F.A.C.: Stationary Sources - Emissions Monitoring; and, Rule 62-4.130, F.A.C.: Plant Operation - Problems.

22. If construction does not commence within 18 months of issuance of this certification, the permittee shall obtain from the DEP's Bureau of Air Regulation a review and, if necessary, a modification of the BACT determination and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2) (1993 version).

23. Quarterly excess emission reports, in accordance with 40 CFR 60.7 and 60.334 (1993 version), shall be submitted to the DEP's Northeast District office.

24. Pursuant to Rule 62-210.370(2), F.A.C., Annual Operating Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur content of the fuel being fired, fuel usage, hours of operation, air emissions limits, etc. Annual operating reports shall be sent to the DEP's Northeast District office by March 1st of each calendar year.

25. Stack sampling facilities shall be installed in accordance with Rule 62-297.345, F.A.C.

Modifications

26. The permittee shall give written notification to the DEP when there is any modification to this facility/emission unit pursuant to Rule 62-212.200, F.A.C., Definitions - Modifications. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of the application/request, if necessary. Such notice shall include, but not be limited to: information describing the precise nature of the change; modification(s) to any emission control system; production capacity of the facility/emissions unit before and after the change; and, the anticipated completion date of the change.

27. An application for Title V operation permit must be submitted to the Tallahassee office no later than 180 days after commencing operation. The permittee shall submit a timely and complete permit application in compliance with the requirements of Chapter 62-213.420.

NOTICE OF RIGHTS

Any party to this Order has the right to seek judicial review of the Order pursuant to Section 120.68, Florida Statutes, by the filing of Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the clerk of the Department of Environmental Protection in the Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400; and by filing a copy of the Notice of Appeal, accompanied by the applicable filing fees, with the appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date that the Final Order is filed with the Department of Environmental Protection.

DONE AND ENTERED this 6th day of April, 1995, in Tallahassee, Florida.

FILING AND ACKNOWLEDGEMENT
FILED, on this date, pursuant to S120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

[signature] 4/06/95
Clerk Date

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell

VIRGINIA B. WETHERELL
Secretary
Marjory Stoneman Douglas Bldg.
3900 Commonwealth Boulevard
Tallahassee, FL 32399-3000
(904) 488-4805

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing was sent by U.S. Mail to the following this 7th day of April, 1995.

James V. Antista, Esquire
General Counsel
Florida Game and Fresh Water Fish Commission
620 South Meridian Street, Rm. 101
Tallahassee, FL 32399-1600

Michael Palecki, Esquire
Florida Public Service Commission
101 East Gaines Street
Fletcher Building, Rm. 212
Tallahassee, FL 32399-0850

Tom Brown, Esquire
Suwannee River Water Management District
Route 3, Box 64
Live Oak, FL 32060

Jane Walker
Florida Defenders of the Environment, Inc.
10601 N.W. 23rd Avenue
Gainesville, FL 32606

Dan Stengle, Esquire
General Counsel
Florida Department of Community Affairs
2740 Centerview, Rm. 138
Tallahassee, FL 32399-2100

Douglas Roberts, Esquire
Hopping Green Sams & Smith
P.O. Box 6526
Tallahassee, FL 32314

Dan Hargrove
2603 NE 17 Terrace
Gainesville, FL 32609-3241

R T Donelan

RICHARD T. DONELAN
Florida Department of Environmental Protection
Assistant General Counsel
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400
(904) 488-9314

HOPPING GREEN SAMS & SMITH
PROFESSIONAL ASSOCIATION
ATTORNEYS AND COUNSELORS
123 SOUTH CALHOUN STREET
POST OFFICE BOX 6526
TALLAHASSEE, FLORIDA 32314
(904) 222-7500
FAX (904) 224-8551
FAX (904) 425-3415

March 20, 1995

Nevin Smith
Department of Environmental Protection
3900 Commonwealth Blvd., Room 1005
Tallahassee, FL 32399

RE: Gainesville Regional Utilities;
Power Plant Certification Modification and PSD Permit

Dear Mr. Smith:

On behalf of Gainesville Regional Utilities, I wish to express our appreciation for the opportunity to meet with you and Richard Donelan on March 13th to discuss the pending modification of site certification for the Deerhaven Generating Station. In that meeting, you indicated the Department is prepared to proceed to issue the final certification order on a timely basis upon resolution of any issues related to the prevention of significant deterioration (PSD) permit.

We understand from the Department's air permitting staff that the separate PSD permit (No PSD-FL-212) is now in a position for issuance, following final review by the air permitting staff. As we discussed last week, GRU currently has a pending request filed with the Department's Office of General Counsel to extend the time in which GRU must file a petition for administrative hearing on the parallel PSD permit. That request would prevent the issuance of any final PSD permit. However, GRU is prepared to withdraw that request and to waive any pending extension upon the issuance of the Department's final order modifying the site certification. This withdrawal would then allow the Department to proceed to issue the final PSD permit.

Therefore, this letter serves as GRU's notice to the Department that upon the issuance of the final certification modification order for this project, GRU waives any pending extension of time concerning the separate PSD permit.

Nevin Smith
March 20, 1995
Page No. 2

GRU looks forward to receiving these approvals in the near future, so that construction on this project may proceed. Should you or your staff have any questions about this matter, please contact me.

Sincerely,

Carolyn Raepple

Carolyn S. Raepple

cc: Ken Plante, OGC
Richard T. Donelan, OGC
Clair Fancy, Bureau of Air Regulation
Raymond O. Manasco, GRU

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

GAINESVILLE REGIONAL UTILITIES
(DEERHAVEN COMBUSTION TURBINE NO. 3),

Petitioner,

vs. OGC CASE NO. 95-0005

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION,

Respondent.
______________________________/

ORDER GRANTING REQUEST FOR EXTENSION
OF TIME TO FILE PETITION FOR HEARING

This cause has come before the Florida Department of Environmental Protection (Department) on receipt of a request made by Petitioner GAINESVILLE REGIONAL UTILITIES under rule 17-103.070 of the Florida Administrative Code to grant an extension of time to file a petition for an administrative hearing on Permit Application No. PSD-FL-212. See Exhibit 1.

Counsel for Petitioner has discussed this request with counsel for the Respondent State of Florida Department of Environmental Protection, which has no objection to it.

Therefore,

IT IS ORDERED:

The request for an extension of time to file a petition for administrative proceeding is granted. Petitioner shall have until April 28, 1995, to file a petition in this matter. Filing shall be complete on receipt by the Office of General

Counsel, Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

DONE AND ORDERED on this 24th day of March, 1995 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

W.H. Cyd fr

KENNETH J. PLANTE
General Counsel

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400
Telephone: (904) 488-9314

CERTIFICATE OF SERVICE

I CEthat a true copy of the foregoing was mailed to:

Douglas S. Roberts
HOPPING GREEN SAMS & SMITH
123 South Calhoun Street
Post Office Box 6526
Tallahassee, Florida 32314

on this 27th day of March, 1995.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

JEFFERSON M. BRASWELL
Assistant General Counsel

2600 Blair Stone Road
Tallahassee, FL 32399-2400
Telephone: (904) 488-9730

HOPPING GREEN SAMS & SMITH
PROFESSIONAL ASSOCIATION
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LISA K. RUSHTON
R. SCOTT RUTH
JULIE R. STEINMEYER

OF COUNSEL
CARLOS ALVAREZ
W. ROBERT FOKES

February 28, 1995

BY HAND DELIVERY

Kenneth Plante, Esquire
Office of General Counsel
Department of Environmental Protection
2600 Blair Stone Road, Room 654
Tallahassee, FL 32399-2400

Re: Gainesville Regional Utilities
Deerhaven Combustion Turbine No. 3
PSD Permit No. PSD-FL-212
Alachua County

Dear Mr. Plante:

Gainesville Regional Utilities ("GRU") received the Department's notice of intent to issue the above-referenced Prevention of Significant Deterioration ("PSD") permit for the construction of a nominal 74 MW combustion turbine at GRU's Deerhaven Generating Station. The notice of intent to issue was received by GRU on December 20, 1994. On December 30, 1994, GRU, through its undersigned counsel, requested an extension of the time in which to file a petition for an administrative hearing on the proposed PSD permit pursuant to Rule 62-103.070, Florida Administrative Code. On January 18, 1995, the Department entered an order granting the request for an extension of time until March 3, 1995.

On behalf of GRU, I hereby request, pursuant to Rule 62-103.070, Florida Administrative Code, an additional extension of the time in which to file a petition for administrative proceedings regarding the PSD permit to and including April 30, 1995. As good cause for granting the request for extension of time for filing, GRU states the following:

1. The proposed permit and attached Technical Evaluation and Preliminary Determination contain numerous Specific Conditions and other matters, several of which appear to warrant clarification or correction.

[redacted]

EXHIBIT 1

2. Over the last several months, GRU has conferred and corresponded with the appropriate representatives of the Department regarding this permit and these conditions. Most of the issues have been resolved in concept, but several conditions remain of concern for GRU. GRU will continue to work with the Department in an attempt to reach final resolution of this matter.

3. This request is filed simply as a protective measure to avoid waiver of GRU's right to challenge the proposed permit. Grant of this request will not prejudice either party, but will further their mutual interest and likely avoid the need to initiate formal administrative proceedings.

4. I hereby certify that I have consulted with Jeffrey Braswell of the Department's Office of General Counsel, and he has indicated he anticipates no Departmental objection to this request.

Accordingly, I hereby request that you formally extend the time for filing of a petition for administrative proceedings in regards to Department PSD Permit No. PSD-FL-212 to and including April 30, 1995.

Sincerely,

Douglas S. Roberts

DSR/gs

cc: Clair Fancy, DEP, Bureau of Air Regulation
Jeffrey Braswell. Esq., DEP OGC
Richard T. Donelan, Esq., DEP OGC
Yolanta Jonynas, GRU
Raymond T. Manasco, Eng., GRU

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February 28, 1995

BY HAND DELIVERY

Kenneth Plante, Esquire
Office of General Counsel
Department of Environmental Protection
2600 Blair Stone Road, Room 654
Tallahassee, FL 32399-2400

Re: Gainesville Regional Utilities
Deerhaven Combustion Turbine No. 3
PSD Permit No. PSD-FL-212
Alachua County

Dear Mr. Plante:

Gainesville Regional Utilities ("GRU") received the Department's notice of intent to issue the above-referenced Prevention of Significant Deterioration ("PSD") permit for the construction of a nominal 74 MW combustion turbine at GRU's Deerhaven Generating Station. The notice of intent to issue was received by GRU on December 20, 1994. On December 30, 1994, GRU, through its undersigned counsel, requested an extension of the time in which to file a petition for an administrative hearing on the proposed PSD permit pursuant to Rule 62-103.070, Florida Administrative Code. On January 18, 1995, the Department entered an order granting the request for an extension of time until March 3, 1995.

On behalf of GRU, I hereby request, pursuant to Rule 62-103.070, Florida Administrative Code, an additional extension of the time in which to file a petition for administrative proceedings regarding the PSD permit to and including April 30, 1995. As good cause for granting the request for extension of time for filing, GRU states the following:

1. The proposed permit and attached Technical Evaluation and Preliminary Determination contain numerous Specific Conditions and other matters, several of which appear to warrant clarification or correction.

2. Over the last several months, GRU has conferred and corresponded with the appropriate representatives of the Department regarding this permit and these conditions. Most of the issues have been resolved in concept, but several conditions remain of concern for GRU. GRU will continue to work with the Department in an attempt to reach final resolution of this matter.

3. This request is filed simply as a protective measure to avoid waiver of GRU's right to challenge the proposed permit. Grant of this request will not prejudice either party, but will further their mutual interest and likely avoid the need to initiate formal administrative proceedings.

4. I hereby certify that I have consulted with Jeffrey Braswell of the Department's Office of General Counsel, and he has indicated he anticipates no Departmental objection to this request.

Accordingly, I hereby request that you formally extend the time for filing of a petition for administrative proceedings in regards to Department PSD Permit No. PSD-FL-212 to and including April 30, 1995.

Sincerely,

Douglas S. Roberts

Douglas S. Roberts

DSR/gs

cc: Clair Fancy, DEP, Bureau of Air Regulation
Jeffrey Braswell. Esq., DEP OGC
Richard T. Donelan, Esq., DEP OGC
Yolanta Jonynas, GRU
Raymond T. Manasco, Eng., GRU

cc: Teresa
Cleve
Buck Oven

GRU
GAINESVILLE REGIONAL UTILITIES
Strategic Planning

Via Fax & Airborne Express

January 23, 1995

RECEIVED
JAN 24 1995
Bureau of
Air Regulation

Mr. John Brown, Administrator Permitting & Standards
Florida Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399

RE: Gainesville Regional Utilities
Deerhaven Combustion Turbine No. 3

Dear Mr. Brown:

Enclosed are Gainesville Regional Utilities' ("GRU") comments with respect to the following documents:

1) Technical Evaluation and Preliminary Determination for the Proposed PSD Permit (PSD-FL-212),

2) Proposed PSD Permit (PSD-FL-212),

3) Best Available Control Technology (BACT) Determination (PSD-FL-212), and

4) Proposed Modifications to Site Certification (PA 74-04)

Specific comments to each document are attached and titled accordingly. General comments regarding two project issues applicable to each document are discussed below. These issues are power augmentation and fuel-bound nitrogen.

Power Augmentation

GRU requested permission to operate for a limited number of hours in the power augmentation ("PA") mode. Recall, power augmentation is an operating mode during which 1) the unit combusts natural gas, 2) water is injected to increase electrical output and 3) the dry low-NO_x combustors are operating as conventional combustors. PA can be used to provide additional power (up to approximately 7 mw) very quickly when the system demand exceeds the on-line generating capacity. The decision whether to operate in the PA mode or put another unit

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on-line, however, would depend on several factors (e.g., cost, expected duration of demand, etc.). For example, if the power demand was small and of short duration and if the proposed unit was already on-line at 100% load, power augmentation might be used to make up the difference. If the demand was higher and of longer duration, another generating unit may be put on-line or power may be purchased from another utility. Specific instances when PA would be used are difficult to detail due to the numerous factors involved in the decision implement it. In any event, PA is not the preferred mode of operation due to the increased wear and tear on the machine and resultant increase in maintenance costs. It does, however, provide GRU with enhanced operating flexibility when additional power is needed on short notice or during emergencies. GRU requests that the Department reconsider PA.

Fuel-Bound Nitrogen

GRU also requested a fuel-bound nitrogen ("FBN") allowance of up to 12 ppm (above the 42 ppm BACT standard) depending on the nitrogen content of the fuel oil. The allowance was requested because water injection, the NO_x control technology utilized during fuel oil combustion, controls thermal NO_x but does not control organic NO_x associated with nitrogen in the fuel oil. Therefore, if the fuel oil contained significant levels of nitrogen (i.e., above 0.015%) the water injection to the unit would have to be increased beyond the manufacturer's recommended levels in order to meet the NO_x limit. This would not only significantly increase water consumption but result in increased wear and tear on the unit and additional maintenance costs.

This issue was discussed with the Department during the September 2, 1994 meeting. The Department requested that GRU submit a Supplemental BACT Analysis detailing the cost of NO_x control via a fuel specification. By letter to Mr. Fancy dated September 19, 1994 GRU submitted this analysis to the Department. The analysis indicated that controlling NO_x via a fuel specification would cost in the range of approximately \$12,000 to \$19,600 per ton of NO_x. Based on recent determinations, these costs are greater than would be considered cost-effective pursuant to EPA BACT guidelines. Furthermore, according to vendor responses, the availability of the lower nitrogen fuel is not assured at any point in time. Therefore, GRU feels the FBN allowance is important to provide reasonable limits and operating conditions during fuel oil combustion and requests that the Department also reconsider the FBN allowance.

GRU has provided comments on these issues in the appropriate sections. Any changes resulting from the Department's reconsideration of these issues should be incorporated into the requirements of the PSD permit and the companion requirements of the Conditions of Certification.

Please call me at (904) 334-3400 Ext. 1284 if you have any questions.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

Enclosures

xc: D. Beck, GRU
D. Fulle, FWI
D. Graziani, FWI
S. Manasco, GRU
H. Oven, FDEP
D. Roberts, HBGS
DHGT3

brownct.y15

GAINESVILLE REGIONAL UTILITIES
DEERHAVEN COMBUSTION TURBINE NO. 3

COMMENTS
TECHNICAL EVALUATION AND PRELIMINARY DETERMINATION
FOR PROPOSED PSD PERMIT (PSD-FL-212)

1) Synopsis of Application - II.3 Facility Category, page 2

The potential emission increases set forth in this section are not consistent with Table 1 and Table 2 contained herein, nor with the proposed PSD permit. The SO_2, CO, VOC and Pb emission increases should be 81, 95.4, 8.66, 0.05746 tons per year ("TPY"), respectively. There should be no separate emission increase indicated for total particulate matter ("PM"). According to the GE data sheets provided in Appendix A of the PSD permit application, PM emissions are comprised entirely of PM_{10}. Therefore, the PM/PM_{10} emission increase is 22 TPY. Inorganic arsenic emissions should be <u>0.004854</u>.

2) Project Description - Page 3

This section does not address two specific issues associated with the proposed project: power augmentation and a fuel-bound nitrogen allowance.

3) IV. Rule Applicability, page 3

Chapter 62-296 F.A.C. is referenced twice. The second reference should be deleted.

4) Page 4, paragraph 1, line 4

Table 400-2 should be Table <u>62-212.</u>400-2

5) V.1 Emission Limitations, page 5

a) Table 1. Maximum Allowable Emission Limits contains a footnote which states that the hourly emission rates (LBS/HR) are calculated using F-factors. In actuality, these values are based on emission data provided by GE and presented in Appendix A of the PSD permit application. DEP's stated intent for this footnote is to indicate that for purposes of demonstrating compliance, F-factors will be used to convert measured pollutant concentrations (ppm) to mass emission rates (lbs/hr). Since NO_x is the only pollutant which whose concentration will be measured, the footnote should only be applicable to hourly NO_x emission rates.

b) The footnote be revised for clarification as follows: "* For purposes of demonstrating compliance, these values ~~are~~ <u>will be</u> calculated using F-factors."

c) The estimated potential emissions in Table 2 are not consistent with the ISO conditions specified (Reference Table 2-1 and Table 2-5 of the PSD permit application). The correct values should be as follows:

VOC: 8.66
Inorganic arsenic: 0.004854
Mercury: 0.0009
Pb: 0.05746
Be: 0.00032

5) Table 3. Maximum Air Quality Impacts for Comparison to the De Minimis Concentrations, page 7

Table 3 indicates a predicted impact for NO_2 in the amount of 0.02 micrograms per cubic meter. This is inconsistent with Table 7-2 of the PSD permit application which indicates an predicted impact of 0.0$\underline{3}$ micrograms per cubic meter.

6) Table 6. Air Toxics Analysis, page 9

The values indicated for certain parameters on Table 6 (attached) are inconsistent with Table 7-6 of the PSD permit application. Correct values have been noted.

Table 5. PSD Class I Increment Analysis
(Ref. Table 7-5 PSD App)

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3) CWNA	Max. Predicted Impact (ug/m^3) OWNA	National Park Service Significant Impact Level (ug/m^3)
NO_2	Annual	0.0047	0.0047	0.025
SO_2	Annual	0.00182	0.00182	0.025
	24-hour	0.063	0.068	0.07
	3-hour	0.303	0.267	0.48
PM_{10}	Annual	0.0003	0.0003	0.08
	24-hour	0.018	0.019	0.33

Table 6. Air Toxics Analysis
(Rf. Table 7-6 PSD App)

	8- hour		24- hour		Annual	
Pollutant	Impact (ug/m^3)	AAC (ug/m^3)	Impact (ug/m^3)	AAC (ug/m^3)	Impact (ug/m^3)	AAC (ug/m^3)
Antimony	0.0004	5	0.0002	1.2	0.000002	0.3
Arsenic	0.00009	2	0.00004	0.48	0.0000005	0.000230
Beryllium	0.000006	0.02	0.000003	0.0048	0.00000003	0.00042
Cadmium	0.00008	0.5	0.00004	0.12	0.0000004	0.00056
Chromium+6	0.0009	0.5	0.0004	0.12	0.000005	0.000083
Cobalt	0.0002	0.5	0.00008	0.12	-	-
Formaldehyde	0.078	12	0.035	2.88	0.0008	0.077
Lead	0.001	0.5	0.0005	0.12	0.000006	0.09
Manganese	0.006	50	0.003	12	- *	- **
Mercury	0.00002	~~0.5~~ 0.1	0.000008	0.~~12~~ .02	0.00000009	0.3
Nickel	0.023	~~0.5~~ 1.0	0.011	0.~~12~~ 24	~~0.0002~~ ***	~~0.0042~~ N/A
Selenium	0.00001	2	0.000004	0.48	- ****	-

Note: AAC = Acceptable Ambient Concentration

* 3.37 E -08
** 4.0 E-01
*** 1.19 E-07
**** 5.25 E -07

GAINESVILLE REGIONAL UTILITIES
DEERHAVEN COMBUSTION TURBINE NO. 3

COMMENTS
PROPOSED PSD PERMIT (PSD-FL-212)

1) Cover Page Attachments Listing - Page 1 of 12

By letter to Mr. Buck Oven dated May 5, 1994 GRU responded to the Department's questions pertaining to the Site Certification modification request/PSD permit application. Included in this letter was a detailed discussion of the conditions under which the power augmentation mode would be utilized and revised storm water management design plans. GRU requests that this letter be referenced in the Attachments listing as follows:

"9. GRU's letter with attachments dated May 5, 1994"

2) Specific Condition 3 - Page 5 of 12, line 4

Correct "operation of fuel oil" to "operation on fuel oil."

3) Specific Condition 6 - Page 6 of 12, line 6

a) GRU requests that emissions during fuel switching and load change be addressed by revising line 6 as follows:

"...malfunction, load change and fuel switching pursuant to Rule 62-210.700, F.A.C.;"

b) This table contains a footnote which states that the hourly emission rates (LBS/HR) were calculated using F-factors. In actuality, these values are based on emission data provided by GE and presented in Appendix A of the PSD permit application. DEP's stated intent of this footnote is to indicate that, for purposes of demonstrating compliance, F-factors will be used to convert measured pollutant concentrations (ppm) to mass emission rates (lbs/hr). Since only NO_x concentrations will be measured, the footnote should be applicable only to NO_x emission rates. GRU requests that:

1) The LBH/HR values for NO_x (i.e., 58 and 184 lbs/hr) be footnoted with the "*".

2) The footnote be revised for clarification as follows: "* For purposes of demonstrating compliance, these values ~~are~~ will be calculated using F-factors."

c) GRU requests that visible emissions during fuel oil operation be permitted at 20% considering 1) the limited number of hours allowed on fuel oil, 2) similar projects that have recently been permitted at 20% and 3) the manufacturer's indication that the lower limit may not be achievable consistently at partial loads.

d) The table indicates that compliance with the PM_{10}, SO_2 and H_2SO_4 mass emission rates will be demonstrated through fuel sulfur analysis. It is GRU's understanding that compliance with the percent sulfur in the fuel will be deemed compliance with the mass emission rates.

4) Specific Condition 7 - Page 7 of 12

GRU requests that this condition be revised as follows: "Visible emissions shall not exceed 10% opacity when firing natural gas or 20% opacity when firing No. 2 fuel oil."

5) Specific Condition 8 - Page 7 of 12

a) The annual emission rates (TPY) indicated in this table are not consistent with the data provided in Table 2-1 and Table 2-5 of the PSD permit application for the ISO conditions specified. The correct values are as follows:

VOC: 8.66
Inorganic arsenic: 0.004854
Mercury: 0.0009
Pb: 0.05746
Be: 0.00032

b) In footnote "**" insert the word "conditions" after ISO on the third line.

6) Specific Condition 9 - Page 8 of 12

GRU requests that the following be inserted in the "Note" paragraph such that use of alternate EPA/DEP reference methods does not require approval from the Secretary.

"Note: No other methods may be used for compliance testing unless prior DEP approval is received in writing. DEP approval to use other reference methods shall not constitute an alternate test method or procedure under Rule 297.620 F.A.C. The DEP..."

7) Specific Condition 10, Page 8 of 12, line 12

This condition allows natural gas supplier data to be used for demonstrating the sulfur content of the natural gas. GRU requests that fuel oil supplier data also be allowed as an alternative consistent with 40 CFR 60.335(e) by revising line 12 as follows:

"natural gas and fuel oil supplier data for sulfur content may be submitted."

8) Specific Condition 12 - Page 8 of 12, starting on line 7

This condition specifies initial and annual testing requirements for the combustion turbine and states that "the combustion turbine shall operate between 95% and 100% of maximum capacity..." The permit is silent with respect to testing at less than this capacity. GRU requests that the following language (consistent with Chapter 62-297.310(2) F.A.C.) be included to address this contingency:

"... compliance test(s). ~~The combustion turbine shall operate between 95% and 100% of maximum capacity for the ambient conditions experienced during compliance test(s).~~ Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 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 v. 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 v. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input and 110 percent of the value reached during the test (corrected for ambient temperature) 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."

9) Specific Condition 13 - Page 9 of 12

This condition addresses excess NO_x emissions which may occur due to temporary and unavoidable combustion instability under certain operating conditions (e.g., startup, load change, fuel switching, etc.). Excess visible emissions may also result under these conditions. Therefore, GRU requests that these be addressed in the same manner as NO_x emissions as follows:

"13. Excess NO_x and visible emissions from this turbine resulting from startup, shutdown, ..."

10) Specific Condition 14 - Page 9 of 12, Provision 14.c.

Condition 14. states that notification and recordkeeping shall be in accordance with 40 CFR 60.7. Subsection (c) states that records shall be maintained for a period of five (5) years. This is inconsistent with 40 CFR 60.7(f) which specifies a two (2) year retention time. GRU requests that this condition be revised as follows:

"c. All measurements...shall be retained for at least ~~five (5)~~ two (2) years..."

11) Specific Condition 15 - Page 10 of 12, line 1 and line 4

a) This condition defines excess emissions as one-hour periods when NO_x emissions are above the BACT standards. GRU requests that this period be revised as indicated below to reflect the agreement reached at the September 2, 1994 meeting between GRU and the Department (reference correspondence from GRU to Mr. Fancy dated September 19, 1994/Attachment listing #7).

"... ~~One hour~~ Twenty-four hour block average (midnight to midnight) periods when..."

b) Line 4 contains a typographical error. Rule 62-297.500 F.A.C. should be Rule 62-297.520.

12) Specific Condition 17 - Page 10 of 12, starting on line 7

GRU requests this condition be revised as indicated below to conform to the monitoring and recordkeeping requirements specified 40 CFR 60.334(b) and 40 CFR 60.7(f), respectively. Also DEP approval of a custom schedule should be indicative of the Department's satisfaction that it is adequate for compliance purposes.

"...will be recognized as enforceable provisions of the permit. ~~, provided that the holder of this permit demonstrates that the provisions of the schedule will be adequate to assure continuous compliance~~. The records...shall be kept by the ~~company~~ permittee for a ~~five~~ two-year period for regulatory agency inspection purposes."

13) Specific Condition 18, page 10 of 12

This condition states that the unit will be in compliance with all applicable provisions of Chapter 62-296 F.A.C. which includes the New Source Performance Standards for Combustion Turbines (Subpart GG). Certain permit conditions, however, provide alternatives to these provisions. For example, Specific Condition 15 requires continuous monitoring of NO_x emissions in lieu of monitoring the water to fuel ratio and fuel-bound nitrogen as required by Subpart GG. Therefore, GRU requests that this condition acknowledge any alternate provisions contained in this permit as follows:

"18. The emission unit shall be in compliance with...F.A.C., except as otherwise specified herein."

14) Specific Condition 19, page 11 of 12

This condition requires compliance with all applicable requirements of Subpart GG. For the reason stated above GRU requests that this condition be revised as follows:

"19. The emission unit shall be in compliance with all applicable requirements of 40 CFR 60, Subpart A, Appendix A and Appendix B (1993 version), Subpart GG - Standards of Performance for Stationary Gas Turbines (1993 version), and Rule 62-296.800(2)(a) F.A.C., except as otherwise specified herein."

15) Specific Condition 21, page 11 of 12, line 4

GRU requests a similar revision of this condition as follows:

"21. Except as otherwise specified herein, ~~T~~the emission unit...(NSPS)"

16) Specific Condition 27, page 12 of 12

a) This condition states that an application for an operation permit must be submitted at least 90 days prior to expiration of the construction permit. This unit is being permitted as a modification to an existing Site Certification pursuant to the Florida Power Plant Siting Act. Therefore, an operating permit under Chapter 62-210 F.A.C. is not required. The new unit, however, will be a Title V source subject to the permitting requirements of Chapter 62-213.420 F.A.C. Pursuant to Chapter 62-213.420(1)(a)(2) F.A.C. an application for an operation permit (which is to be issued by Tallahassee, not the District) is to be filed no later than 180 days after commencing operation. Therefore, GRU requests that this condition be revised accordingly as follows:

"27. An application for a~~n~~ Title V operation permit must be submitted to the ~~Northeast District~~ Tallahassee office ~~at least 90 days prior to the expiration date of this construction permit~~ no later than 180 days after commencing operation. The permittee shall submit a timely and complete permit application in compliance with the requirements of Chapter 62-213.420."

GAINESVILLE REGIONAL UTILITIES
DEERHAVEN COMBUSTION TURBINE NO. 3

COMMENTS
BACT DETERMINATION

1) Table of Potential Emissions - Page 1

The values indicated on this table are not correct for the operating conditions specified (Reference Table 2-5 of the PSD permit application). The correct values should be as follows:

Be: 0.00032
Hg: 0.0009
Pb: 0.05746
As: 0.004854

2) BACT Determination by the Department - NO_x Control, Page 7

In its permit application, GRU requested an allowance for fuel-bound nitrogen and an operating mode called power augmentation. To support its request, GRU provided the Department with additional information, including a Supplemental BACT Analysis for fuel oil. This analysis indicated that the cost of NO_x control via a fuel specification for nitrogen was in the range of $12,000 to $19,600 per ton of NO_x. In its BACT determination, the Department states that "no allowance has been made for fuel bound nitrogen or for operation with power augmentation" but provides no rationale for its decision. GRU requests that the Department change its determination or provide its rationale.

3) BACT Standards - page 8

This table contains a footnote which states that the hourly emission rates (LBS/HR) were calculated using F-factors. In actuality, these values are based on emission data provided by GE and presented in Appendix A of the PSD permit application. DEP's stated intent of this footnote is to indicate that for purposes of demonstrating compliance, F-factors will be used to convert measured pollutant concentrations (ppm) to mass emission rates (lbs/hr). Since only NO_x concentrations will be measured, the footnote should only be applicable to NO_x emission rates. GRU requests that:

a) The LBH/HR values for NO_x (i.e., 58 and 184 lbs/hr) be footnoted with the "*".

b) The footnote be revised for clarification as follows: "For purposes of demonstrating compliance, these values ~~are~~ will be calculated using F-factors."

4) Monitoring - page 8

a) This section states that the BACT emission limitations for NO_x are one-hour averages. GRU requests that this period be revised as indicated below to reflect the agreement reached at the September 2, 1994 meeting between GRU and the Department (reference correspondence dated September 19, 1994 from GRU to Mr. Fancy).

"The BACT emission limitations for NO_x are ~~one~~ twenty four-hour block averages (midnight to midnight)."

b) This section also states that NO_x emissions will be monitored with a continuous emission monitoring systems ("CEM"). A NO_x CEM by definition consists of a NO_x and diluent (e.g., oxygen or carbon dioxide) analyzer. The use of a particular diluent may depend on site-specific factors and should be left to the permittee's discretion. GRU requests that the requirement for an oxygen monitor be deleted follows: "...monitoring system (CEM) for NO_x ~~and oxygen~~."

5) Monitoring - page 9, first paragraph, last line

GRU requests that the requirement for an oxygen monitor be deleted as follows: "...NO_x ~~and oxygen~~ CEMS."

GAINESVILLE REGIONAL UTILITIES
DEERHAVEN COMBUSTION TURBINE NO. 3

COMMENTS
PROPOSED CONDITIONS OF CERTIFICATION

1) H. Deerhaven Combustion Turbine No. 3 - page 2, line 4

This condition states that the construction and operation of the unit will be in accordance with all applicable provisions of 40 CFR 60, Subpart GG and Chapter 62-210 through 297. Certain permit conditions, however, provide alternatives to these provisions. For example, Specific Condition 15 requires continuous monitoring of NO_x emissions in lieu of monitoring the water to fuel ratio and fuel-bound nitrogen as required by Subpart GG. Therefore, GRU requests that this condition acknowledge any alternate provisions contained in this permit as follows:

"...Subpart A, Subpart GG, Appendix A and Appendix B (1993 version), except as otherwise specified herein."

2) General Operating Requirement 3. - page 2, line 3

There is a typographical error on line 3. The "of" after "operation" should be on."

3) Emission Limits - page 3 Specific Condition 6 - Page 6 of 12, line 4

a) GRU requests that emissions during fuel switching and load change be addressed by revising line 4 as follows:

"...malfunction, load change and fuel switching pursuant to Rule 62-210.700, F.A.C.;"

4) Maximum Allowable Emission Limits - page 4

a) The TPY in the table is footnoted to indicate that the "values are calculated using F-factors." The annual emissions (TPY) are, in fact, based on permitted hours of operation and GE's emission data provided in Appendix A of the PSD permit application. DEP's stated intent for the footnote was to indicate that F-factor calculations, which can be used to convert concentrations (ppm) to emission rates (lbs/hr), would be used for demonstrating compliance with the mass emission limits. This footnote should be applicable only to NO_x because it is the only pollutant whose concentration is measured. GRU requests that:

1) The "*" next to the TPY be deleted.

2) The LBH/HR values for NO_x (i.e., 58 and 184 lbs/hr) be footnoted with the "*".

3) The footnote be revised for clarification as follows: "For purposes of demonstrating compliance, these values ~~are~~ will be calculated using F-factors."

b) GRU requests that visible emissions during fuel oil operation be permitted at 20% considering 1) the limited number of hours allowed on fuel oil, 2) similar projects that have recently been permitted at 20% and 3) the manufacturer's indication that the lower limit may not be achievable consistently at partial loads.

c) There is a typographical error in the SO_2 TPY footnote for oil. The "(c)" should be "(d)."

d) There is a typographical error in the BACT Standard column for NO_x on fuel oil. The "e" should be "@".

5) General Operating Requirement 7. - page 5

GRU requests this condition be revised as follows:

"7. Visible emissions shall not exceed 10% opacity when firing natural gas or 20% opacity when firing No. 2 fuel oil.

6) General Operating Requirement 8. - page 5

a) The annual emission rates (TPY) indicated in this table are not consistent with the data provided in Table 2-1 and Table 2-5 of the PSD permit application for the ISO conditions specified. The correct values are as follows:

CO: 95.4
VOC: 8.66
Inorganic arsenic: 0.004854
Mercury: 0.0009
Pb: 0.05746
Be: 0.00032

b) Footnote ** should have the word "conditions" inserted after "ISO" on the second line.

7) General Operating Requirement 9. - pages 5 and 6

a) The second paragraph on page 5 should be underlined in its entirety to indicate this is a new requirement.

b) GRU requests that the following be inserted on page 6 in the "Note" paragraph such that use of alternate EPA/DEP reference methods does not require approval from the Secretary.

"Note: No other methods may be used for compliance testing unless prior DEP approval is received in writing. DEP approval to use other reference methods shall not constitute an alternate test method or procedure under Rule 297.620 F.A.C. The DEP..."

8) General Operating Requirement 10. - page 6

a) "$5O_2$" should be "SO_2"
b) "H_25O4" should be "H_2SO4"
c) "PM$\sim_0$" should be "PM_{10}"
d) This condition allows natural gas supplier data to be used for demonstrating the sulfur content of the natural gas. GRU requests that fuel oil supplier data also be allowed as an alternative consistent with 40 CFR 60.335(e) by revising line 8 of this requirement as follows:

"natural gas and fuel oil supplier data for sulfur content may be submitted."

9) General Operating Requirement 12. - page 7

This condition specifies initial and annual testing requirements for the combustion turbine and states that "the combustion turbine shall operate between 95% and 100% of maximum capacity..." The permit is silent with respect to testing at less than this capacity. GRU requests that the following language (consistent with Chapter 62-297.310(2) F.A.C.) be included to address this contingency:

"The DEP"s Northeast District... compliance test(s). ~~The combustion turbine shall operate between 95% and 100% of maximum capacity for the ambient conditions experienced during compliance test(s).~~ Testing of emissions shall be conducted with the combustion turbine operating at permitted capacity. Permitted capacity is defined as 95-100 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 v. 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 v. ambient temperature curve downward by an increment equal to the difference between the maximum permitted heat input and 110 percent of the value reached during the test (corrected for ambient temperature) 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. The turbine..."

10) General Operating Requirement 13. - page 7

This condition addresses excess NO_x emissions which may occur due to temporary and unavoidable combustion instability under certain operating conditions (e.g., startup, load change, fuel switching, etc.). Excess visible emissions may also result under these conditions. Therefore, GRU requests that these be addressed in the same manner as NO_x emissions as follows:

"13. Excess NO_x and visible emissions from this turbine resulting from startup, shutdown, ..."

11) General Operating Requirement 15. - page 8, line 5

This line contains a typographical error. Rule 62-297.500 F.A.C. should be Rule 62-297.520.

12) General Operating Requirement 17. - Page 9

GRU requests this condition be revised as indicated below to conform to the monitoring and recordkeeping requirements specified 40 CFR 60.334(b) and 40 CFR 60.7(f), respectively. Also DEP approval of a custom schedule should be indicative of the Department's satisfaction that it is adequate for compliance purposes.

"...will be recognized as enforceable provisions of the permit. ~~, provided that the holder of this permit demonstrates that the provisions of the schedule will be adequate to assure continuous compliance~~ The records...shall be kept by the ~~company~~ permittee for a ~~five~~ two-year period for regulatory agency inspection purposes."

13) General Operating Requirement 18. - page 9

GRU requests revision of this condition as follows for the reason stated in Comment 1 above:

"18. The emission unit shall be in compliance with...F.A.C., except as otherwise specified herein."

14) General Operating Requirement 19. - page 9, line 3

GRU requests a similar revision of this condition as follows:

"19. The emission unit...Rule 62-296.800(2)(a)37., F.A.C., except as otherwise specified herein."

15) General Operating Requirement 21 - page 10

GRU requests this condition be revised as follows:

"21. Except as otherwise specified herein, ~~T~~the emission unit..."

NOTE: Specific Condition 27 of the Proposed PSD permit has not been incorporated herein.

GRU

GAINESVILLE REGIONAL UTILITIES

P. O. Box 147117, Sta. A136, Gainesville, FL 32614-7117

Patty - John gave this to me for further handling, so I already read it. Al

To: Mr. John Brown
Fla. Dept. Envir. Protection

FAX #: 904-922-6979

Phone: 904-488-1344

From: Yolanta E. Jonynas

FAX #: (904) 334-3151

Phone: (904) 334-3400 ext. 1284

Number of pages sent: 19 (Including this cover sheet)

Date sent: January 23, 1995

COMMENTS: Marcia, Please confirm timely receipt of this letter by sending me the cover letter with a date stamp. Thanks!

Kim - Discuss with Patty how to update status report to show we received this from Gainesville Utilities. I'd like Marty to get a copy as well as Mike Harley. Teresa is main engineer. Set up a meeting for us to discuss what to do, for about 1 week from now. Al

Street Address: 301 SE 4th Avenue, Gainesville, FL 32601

United States Department of the Interior

FISH AND WILDLIFE SERVICE
1875 Century Boulevard
Atlanta, Georgia 30345

IN REPLY REFER TO:

January 5, 1995

RECEIVED
JAN 10 1995
Bureau of
Air Regulation

Mr. Clair H. Fancy
Chief, Bureau of Air Regulation
Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399

Dear Mr. Fancy:

We have reviewed the Technical Evaluation and Preliminary Determination and the proposed permit for a 74 MW simple cycle combustion turbine at Gainesville Regional Utilities' existing facility in Alachua County. The facility is located approximately 90 km southwest of Okefenokee Wilderness Area (WA) and 110 km northeast of Chassahowitzka WA, Class I air quality areas, administered by the Fish and Wildlife Service (Service). The project is PSD significant for sulfur dioxide (SO_2), nitrogen oxides (NO_x), PM10, and sulfuric acid mist (H_2SO_4).

Best Available Control Technology (BACT)

We understand that the turbine will fire natural gas, with No. 2 fuel oil (maximum 0.05 percent sulfur) as a backup. The turbine is to operate no more than 3900 hours per year and is to be fired by fuel oil no more than 2000 hours per year. NO_x emissions will be controlled by dry low-NO_x combustors, with water injection during fuel oil firing. SO_2 and H_2SO_4 emissions will be controlled by the use of natural gas and low sulfur fuel oil. Although we believe that this represents BACT for the project, we request that the NO_x emission limits be revised if monitoring demonstrates that rates lower than 15 ppm (gas firing) and 42 ppm (oil firing) can be achieved on a consistent basis.

Air Quality Modeling Analysis

Air quality impacts from the project at the two Class I wilderness areas were modeled with the ISCST2 model. The maximum predicted impacts of SO_2 and NO_x emissions at the wilderness areas were below the Service's recommended significant impact levels. Therefore, the project will not contribute significantly to Class I increment consumption at the wilderness areas. A VISCREEN analysis predicted that there would be no coherent plume impacts from the proposed project at the wilderness areas.

Air Quality Related Values (AQRV) Analysis

The applicant did not perform a detailed AQRV analysis. This is acceptable to us, as agreed upon in a pre-application discussion between the Service and the applicant on January 28, 1994. At that time, it was agreed that a detailed AQRV analysis would not be required because of the proposed project emissions levels, the proposed BACT control levels, the distances to the Class I areas, and the results of the preliminary dispersion modeling analysis.

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 303/969-2071.

Sincerely yours,

Jerome M. Butler, Ph.D.
Acting Regional Director

cc: J. Heron
C. Holladay
B. Owen
C. Kirts, NE Dist,
J. Harper, EPA
Y. Gonynas, GRU

Petty - FYI
al

INTEROFFICE MEMORANDUM

Date: 04-Jan-1995 02:34pm EST
From: Marjane Monahan TAL
MONAHAN_M
Dept: Office General Counsel
Tel No: 904/488-9730
SUNCOM: 278-9730

TO: Clair Fancy TAL (FANCY_C)

CC: Jeff Braswell TAL (BRASWELL_J)

Subject: Gainesville Regional Utilities

Re: Gainesville Regional Utilities (GRU)
Deerhaven Combustion Turbine No. 3
PSD-FL-212

OGC has received a request for an extension of time to file a petition for an administrative hearing regarding the above-captioned matter. Jeff Braswell is the attorney assigned to the case. The OGC case number is 95-0005.

OGC will be granting GRU an extension of time until March 3, 1995. Please send a copy of the notice of intent to issue to my attention at MS#35. Thank you.

Sincerely,
Marjane C. Monahan

sent
PA

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning

Via Telecopy & Airborne Express

January 4, 1995

RECEIVED

JAN 05 1995

Bureau of Air Regulation

Mr. Clair Fancy
Florida Dept. of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Notice of Intent to Issue Permit
Proof of Publication

Dear Mr. Fancy:

Enclosed please find the proof of publication of the Department's Notice of Intent to Issue a PSD Permit for construction of the new combustion turbine at the Deerhaven Generating Station. This notice was published in the legal section of the Gainesville Sun on December 24, 1994. We apologize for the delay in transmitting this proof to your office; however, as you are aware, it was not available until today.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

Enclosures

cc: J. Heron
B. Oven
C. Kirts, NED
J. Harper, EPA
J. Bunyak, NPS
J. Braswell, OGC

PROOFDEP.W3

(904) 334-3400 ext. 1261 P.O. Box 147117, Station A136, Gainesville, Florida 32614-7117 Fax: (904) 334-3151

NO. 8895

THE GAINESVILLE SUN
Published Daily and Sunday
GAINESVILLE, FLORIDA

STATE OF FLORIDA
COUNTY OF ALACHUA

Before the undersigned authority personally appeared ....Naomi Williams-Jordan....................

who on oath says that he/she is ..Classified Assistant Mgr... of THE GAINESVILLE SUN, a daily

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

....Notice of Intent..

in the matter of ....

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

....December 24,.. 19....94..........

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 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.

Naomi Williams-Jordan
....

Sworn to and subscribed before me this

...4..... day of Jan A.D., 19..95...

Martha A. Pattison

(Seal) Notary Public

MARTHA A. PATTISON
MY COMMISSION EXPIRES APRIL 8, 1998
#CC 357802
Bonded thru Troy Fain-Insurance
NOTARY PUBLIC, STATE OF FLORIDA

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION NOTICE OF INTENT TO ISSUE PERMIT
PSD-FL-212

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD permit to the Gainesville Regional Utilities (GRU) to construct a 74 MW simple cycle combustion turbine at GRU's existing facility. The facility is located off US 441 North in Alachua County, Florida. The project is subject to review under the Prevention of Significant Deterioration (PSD) regulations for the following pollutants: sulfur dioxide, nitrogen oxides, sulfuric acid mist and particulate matter. A determination of Best Available Control Technology (BACT) was required for these pollutants. The maximum predicted increases in ambient sulfur dioxide, nitrogen dioxide, and particulate matter concentrations due to this project are all less than the respective PSD Class I and II significant impact levels; thus, no PSD increment consumption was calculated for this project.

The Department is issuing this Intent to Issue for the reasons stated in the Technical Evaluation and Preliminary Determination.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of publication of this Notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitue a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

The Petition shall contain the following information: (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, 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 decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, Florida Administrative Code.

The Application is available for public inspection during normal business hours, 8:00 am to 5:00 pm, Monday through Friday, except legal holidays, at: Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Department of Environmental Protection
Northeast District
7825 Baymeadows Way Suite B200
Jacksonville, Florida 32256-7577
Department of Environmental Protection,
Northeast District Branch Office
5700 Southwest 34th Street, Suite 1204
Gainesville, Florida 32608

Any person may send written comments on the proposed action to Mr. John Brown at the Department's Tallahassee address. All comments received within 30 days of the publication of this Notice will be considered in the Department's final determination.

Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this Notice.

(8895) 12:24

GRU

GAINESVILLE REGIONAL UTILITIES

P. O. Box 147117, Sta. A136, Gainesville, FL 32614-7117

RECEIVED
JAN 05 1995
Bureau of Air Regulation

To: CLAIR FANCY FAX #: 904/922-6979

Phone: 904/488-1344

From: Yolanta E. Jonynas FAX #: (904) 334-3151

Phone: (904) 334-3400 ext. 1284

Number of pages sent: 4 (Including this cover sheet)

Date sent: 1/04/95

COMMENTS:

Street Address: 301 SE 4th Avenue, Gainesville, FL 32601

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

GAINESVILLE REGIONAL UTILITIES
(DEERHAVEN COMBUSTION TURBINE NO. 3),

Petitioner,

vs. OGC CASE NO. 95-0005

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION,

Respondent.
_______________________________/

ORDER GRANTING REQUEST FOR EXTENSION
OF TIME TO FILE PETITION FOR HEARING

This cause has come before the Florida Department of Environmental Protection (Department) on receipt of a request made by Petitioner GAINESVILLE REGIONAL UTILITIES under rule 17-103.070 of the Florida Administrative Code to grant an extension of time to file a petition for an administrative hearing on Application No. PSD-FL-212. See Exhibit 1.

Counsel for Petitioner has discussed this request with counsel for the Respondent State of Florida Department of Environmental Protection, which has no objection to it.

Therefore,

IT IS ORDERED:

The request for an extension of time to file a petition for administrative proceeding is granted. Petitioner shall have until March 3, 1995, to file a petition in this matter. Filing shall be complete on receipt by the Office of General

Counsel, Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

DONE AND ORDERED on this 18th day of January, 1995 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

W.H. Congdon for

KENNETH J. PLANTE
General Counsel

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400
Telephone: (904) 488-9314

CERTIFICATE OF SERVICE

I CERTIFY that a true copy of the foregoing was mailed to:

Douglas S. Roberts
HOPPING BOYD GREEN & SAMS
123 South Calhoun Street
Post Office Box 6526
Tallahassee, Florida 32314

on this 23rd day of January, 1995.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

JEFFERSON M. BRASWELL
Assistant General Counsel

2600 Blair Stone Road
Tallahassee, FL 32399-2400
Telephone: (904) 488-9730

HOPPING BOYD GREEN & SAMS
ATTORNEYS AND COUNSELORS
123 SOUTH CALHOUN STREET
POST OFFICE BOX 6526
TALLAHASSEE, FLORIDA 32314
(904) 222-7500
FAX (904) 224-8551
FAX (904) 425-3415

CARLOS ALVAREZ
JAMES S. ALVES
BRIAN H. BIBEAU
KATHLEEN BLIZZARD
ELIZABETH C. BOWMAN
WILLIAM L. BOYD, IV
RICHARD S. BRIGHTMAN
PETER C. CUNNINGHAM
RALPH A. DEMEO
THOMAS M. DEROSE
WILLIAM H. GREEN
WADE L. HOPPING
FRANK E. MATTHEWS
RICHARD D. MELSON
DAVID L. POWELL
WILLIAM D. PRESTON
CAROLYN S. RAEPPLE
GARY P. SAMS
ROBERT P. SMITH
CHERYL G. STUART

KRISTIN M. CONROY
C. ALLEN CULP, JR.
CONNIE C. DURRENCE
JONATHAN S. FOX
JAMES C. GOODLETT
GARY K. HUNTER, JR.
DALANA W. JOHNSON
JONATHAN T. JOHNSON
ANGELA R. MORRISON
MARIBEL N. NICHOLSON
GARY V. PERKO
KAREN M. PETERSON
MICHAEL P. PETROVICH
DOUGLAS S. ROBERTS
R. SCOTT RUTH
JULIE R. STEINMEYER

OF COUNSEL
W. ROBERT FOKES

December 30, 1994

BY HAND DELIVERY

Kenneth Plante, Esquire
Office of General Counsel
Department of Environmental Protection
2600 Blair Stone Road, Room 654
Tallahassee, FL 32399-2400

Re: Gainesville Regional Utilities
Deerhaven Combustion Turbine No. 3
PSD Permit No. PSD-FL-212
Alachua County

Dear Mr. Plante:

Gainesville Regional Utilities ("GRU") received the Department's notice of intent to issue the above-referenced Presentation of Significant Deterioration ("PSD") permit for the construction of a nominal 74 MW combustion turbine at GRU's Deerhaven Generating station. The notice of intent to issue was received by GRU on December 20, 1994. The notice of intent was issued by the Department's Bureau of Air Regulation and signed by Mr. Clair Fancy, Bureau Chief. Pursuant to the notice of intent, GRU has until January 4, 1995 to file a petition for an administrative hearing regarding the permit.

On behalf of GRU, I hereby request, pursuant to Rule 62-103.070, Florida Administrative Code, an extension to and including March 3, 1995, in which to file a petition for administrative proceedings regarding the permit. As good cause for granting the request for extension of time for filing, GRU states the following:

1. The proposed permit and attached Technical Evaluation and Preliminary Determination contain numerous Specific Conditions and other matters, several of which appear to warrant clarification or correction.

[redacted]

EXHIBIT 1

2. Over the last several months, GRU has conferred and corresponded with the appropriate representatives of the Department regarding this permit and these conditions. Most of the issues have been resolved in concept, but several conditions remain of concern for GRU. GRU will continue to work with the Department in an attempt to reach final resolution of this matter.

3. This request is filed simply as a protective measure to avoid waiver of GRU's right to challenge the proposed permit. Grant of this request will not prejudice either party, but will further their mutual interest and likely avoid the need to initiate formal administrative proceedings.

4. I hereby certify that I have attempted, without success, to contact Jeffrey Braswell of the Department's Office of General Counsel to ascertain whether he would have an objection to this request.

Accordingly, I hereby request that you formally extend the time for filing of a petition for administrative proceedings in regards to Department PSD Permit No. PSD-FL-212 to and including March 3, 1995.

Sincerely,

Douglas S. Roberts

Douglas S. Roberts

DSR/gs

cc: Clair Fancy, DEP, Bureau of Air Regulation
Jeffrey Braswell. Esq., DEP OGC
Yolanta Jonynas, GRU

HOPPING BOYD GREEN & SAMS

ATTORNEYS AND COUNSELORS

123 SOUTH CALHOUN STREET

POST OFFICE BOX 6526

TALLAHASSEE, FLORIDA 32314

(904) 222-7500

FAX (904) 224-8551

FAX (904) 425-3415

RECEIVED
DEC 30 1994
Bureau of Air Regulation

December 30, 1994

BY HAND DELIVERY

Kenneth Plante, Esquire
Office of General Counsel
Department of Environmental Protection
2600 Blair Stone Road, Room 654
Tallahassee, FL 32399-2400

Re: Gainesville Regional Utilities
Deerhaven Combustion Turbine No. 3
PSD Permit No. PSD-FL-212
Alachua County

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1. The proposed permit and attached Technical Evaluation and Preliminary Determination contain numerous Specific Conditions and other matters, several of which appear to warrant clarification or correction.

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4. I hereby certify that I have attempted, without success, to contact Jeffrey Braswell of the Department's Office of General Counsel to ascertain whether he would have an objection to this request.

Accordingly, I hereby request that you formally extend the time for filing of a petition for administrative proceedings in regards to Department PSD Permit No. PSD-FL-212 to and including March 3, 1995.

Sincerely,

Douglas S. Roberts

Douglas S. Roberts

DSR/gs

cc: Clair Fancy, DEP, Bureau of Air Regulation
Jeffrey Braswell. Esq., DEP OGC
Yolanta Jonynas, GRU

J. Heron
B. Oven
C. Kirts, NE Dist

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

December 16, 1994

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. Michael L. Kurtz
General Manager for Utilities
Gainesville Regional Utilities
P. O. Box 147117 - Station A-134
Gainesville, Florida 32614-7117

Dear Mr. Kurtz:

Attached is one copy of the Technical Evaluation and Preliminary Determination, proposed BACT determination, and proposed permit to construct a 74 MW simply cycle combustion turbine at Gainesville Regional Utilities's existing facility located off US 441 North in Alachua County, Florida.

Please submit any written comments you wish to have considered concerning the Department's proposed action to Mr. John Brown of the Bureau of Air Regulation.

Sincerely,

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

CHF/TH/bjb

Attachments

cc: C. Kirts, NED
J. Harper, EPA
J. Bunyak, NPS
B. Oven, PPS, DEP
D. Graziani, P.E., FWI

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Michael L. Kurtz
General Manager for Utilities
Gainesville Regional Utilities
P. O. Box 147117 - Station A-134
Gainesville, FL 3261407117

4a. Article Number
P 872 562 688

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

7. Date of Delivery
DEC 21 1994

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 872 562 688

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to Mr. Michael L. Kurtz, GRU	
Street and No. P. O. Box 147117 Sta. A-134	
P.O., State and ZIP Code Gainesville, FL 32614-7117	
Postage	$
Certified Fee	
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PS Form **3800**, JUNE 1991

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

CERTIFIED MAIL

In the Matter of an
Application for Permit by:

DEP File No. PSD-FL-212
Alachua County

City of Gainesville,
Gainesville Regional Utilities
P. O. Box 147117, Station A-134
Gainesville, Florida 32614-7117
______________________________/

INTENT TO ISSUE

The Department of Environmental Protection (Department) gives notice of its intent to issue a permit (copy attached) for the proposed project as detailed in the application specified above, for the reasons stated in the attached Technical Evaluation and Preliminary Determination.

The applicant, the City of Gainesville, applied on March 22, 1994, to the Department for a permit to construct a 74 MW simple cycle combustion turbine at Gainesville Regional Utilities's existing facility. The facility is located off US 441 North in Alachua County, Florida.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes (F.S.), and Chapters 62-212 and 62-4, Florida Administrative Code (F.A.C.). The project is not exempt from permitting procedures. The Department has determined that a construction permit is required for the proposed work.

Pursuant to Section 403.815, F.S. and Rule 62-103.150, F.A.C., you (the applicant) are required to publish at your own expense the enclosed Notice of Intent to Issue Permit. The notice shall be published one time only within 30 days in the legal ad section of a newspaper of general circulation in the area affected. For the purpose of this rule, "publication in a newspaper of general circulation in the area affected" means publication in a newspaper meeting the requirements of Sections 50.011 and 50.031, F.S., in the county where the activity is to take place. The applicant shall provide proof of publication to the Department's Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within seven days of publication. Failure to publish the notice and provide proof of publication within the allotted time may result in the denial of the permit.

The Department will issue the permit with the attached conditions unless a petition for an administrative proceeding (hearing) is filed pursuant to the provisions of Section 120.57, F.S.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, F.S. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400. Petitions filed by the permit applicant and the parties listed below must be filed within 14 days of receipt of this intent. Petitions filed by other persons must be filed within 14 days of publication of the public notice or within 14 days of their receipt of this intent, whichever first occurs. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

The Petition shall contain the following information;

(a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed;
(b) A statement of how and when each petitioner received notice of the Department's action or proposed action;
(c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action;
(d) A statement of the material facts disputed by Petitioner, if any;
(e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action;
(f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and,
(g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this intent. Persons whose substantial interests will be affected by any decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of receipt of this intent in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, F.A.C.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

C. H. Fancy, P.E., Chief
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399
904-488-1344

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this INTENT TO ISSUE and all copies were mailed by certified mail before the close of business on 12/19/94 to the listed persons.

Clerk Stamp

FILING AND ACKNOWLEDGMENT
FILED, on this date, pursuant to §120.52(11), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Charlotte J. Hayes 12/19/94
Clerk Date

Copies furnished to:

C. Kirts, NED
J. Harper, EPA
J. Bunyak, NPS
B. Oven, PPS, DEP
D. Graziani, P.E., FWI

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NOTICE OF INTENT TO ISSUE PERMIT

PSD-FL-212

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD permit to the Gainesville Regional Utilities (GRU) to construct a 74 MW simple cycle combustion turbine at GRU's existing facility. The facility is located off US 441 North in Alachua County, Florida. The project is subject to review under the Prevention of Significant Deterioration (PSD) regulations for the following pollutants: sulfur dioxide, nitrogen oxides, sulfuric acid mist and particulate matter. A determination of Best Available Control Technology (BACT) was required for these pollutants. The maximum predicted increases in ambient sulfur dioxide, nitrogen dioxide, and particulate matter concentrations due to this project are all less than the respective PSD Class I and II significant impact levels; thus, no PSD increment consumption was calculated for this project. The Department is issuing this Intent to Issue for the reasons stated in the Technical Evaluation and Preliminary Determination.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of publication of this notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitute a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

The Petition shall contain the following information; (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversal or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and, (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, 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 decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, Florida Administrative Code.

The application is available for public inspection during normal business hours, 8:00 a.m. to 5:00 p.m., Monday through Friday, except legal holidays, at:

Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301

Department of Environmental Protection
Northeast District
7825 Baymeadows Way, Ste. B200
Jacksonville, Florida 32256-7577

Department of Environmental Protection
Northeast District Branch Office
5700 Southwest 34th Street, Suite 1204
Gainesville, Florida 32608

Any person may send written comments on the proposed action to Mr. John Brown at the Department's Tallahassee address. All comments received within 30 days of the publication of this notice will be considered in the Department's final determination.

Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this notice.

Technical Evaluation
and
Preliminary Determination

Gainesville Regional Utilities
Deerhaven Generating Station
Gainesville, Alachua County, Florida

74 MW Simple Cycle Combustion Turbine

Permit Number: PSD-FL-212

Department of Environmental Protection
Division of Air Resources Management
Bureau of Air Regulation

December 16, 1994

SYNOPSIS OF APPLICATION

I. NAME AND ADDRESS OF APPLICANT

City of Gainesville, Gainesville Regional Utilities
P. O. Box 147117, Station A-134
Gainesville, Florida 32614-7117

II. FACILITY INFORMATION

II.1 Facility Location

This facility is located at its existing Deerhaven site approximately seven miles north of Gainesville, in Alachua County, Florida. The UTM coordinates are Zone 17, 365.5 km East and 3292.7 km North.

II.2 Facility Identification Code (SIC)

Major Group No. 49 - Electric, Gas and Sanitary Services.

Industry Group No. 491 - Combination Electric, Gas and Other Utility Services.

Industry Group No. 4911 - Electric and Other Services Combined.

II.3 Facility Category

Gainesville Regional Utilities is classified as a major emitting facility. The proposed project, a 74 MW nominal/dual fuel simple cycle combustion turbine (CT), will increase emissions approximately by 239 tons per year (TPY) of nitrogen oxides (NO_x); 79 TPY of sulfur dioxide (SO_2); 96 TPY of carbon monoxide (CO); 22 TPY of particulate matter (PM); 7 TPY of PM less than 10 microns in diameter (PM_{10}); 9 TPY of volatile organic compounds (VOC); 0.00032 TPY of beryllium (Be); 0.0638 TPY of lead (Pb); 0.001 TPY of mercury (Hg); and 9 TPY of sulfuric acid (H_2SO_4) mist, if the combustion turbine is operated at 3900 total hours per year and up to 2000 hours per year on No. 2 fuel oil (max. 0.05% Sulfur content, by weight) at 100% load.

III. PROJECT DESCRIPTION

The proposed project will consist of the construction of a new simple cycle CT at the existing Deerhaven Generating Station. It will be designated as DHCT3. The new CT will provide a nominal 74 MW of additional generating capacity to the site. The CT will fire natural gas and No. 2 fuel oil (max. 0.05% Sulfur content, by weight) and will function as an intermediate peaking unit, operating no more than 3,900 total hours per year. The CT selected is a General Electric (GE) Model MS7001EA dry low NO_x unit. It will be capable of operating in any of these two modes: natural gas firing (NGF) or distillate fuel oil firing (FOF).

During NGF operations, oxides of nitrogen (NO_x) emissions will be controlled through the use of staged combustion with GE dry low NO_x combustors. During FOF operation, NO_x emissions will be controlled by the use of water injection to reduce peak flame temperature. The SO_2 and H_2SO_4 mist emissions will be controlled through the use of natural gas and by limiting the use of low sulfur fuel oil to no more than 2,000 hours per year. The CO, VOC and PM emissions will be controlled through good combustion practices. PM emissions will be further reduced by filtering the combustion air.

The existing Deerhaven Generating Station consists of two steam generating units [a nominal 81 MW gas/oil fired unit (Unit 1) and a nominal 235 MW coal fired unit (Unit 2)], and two nominal 22 MW gas/oil fired CTs, designated DHCT1 and DHCT2. The coal fired unit was licensed through the Florida Power Plant Siting Act (PPSA) process jurisdiction. The addition of the new gas/oil fired CT is being treated as a modification of the 1978 site certification.

IV. RULE APPLICABILITY

The proposed project, construction of a 74 MW simple cycle CT, is subject to preconstruction review under the provisions of Chapter 403, Florida Statutes, Chapters 62-4 and 62-210, 62-212, 62-272, 62-275, 62-296 and 62-296, Florida Administrative Code (F.A.C.).

This facility is located in an area designated attainment for all criteria pollutants in accordance with Rule 62-275.400, F.A.C.

The proposed emission unit is subject to the Prevention of Significant Deterioration (PSD) regulation (62-212.400, F.A.C.) because the requested increase in SO_2, NO_X, PM_{10} and H_2SO_4 exceed the significant emission rates (Table 400-2, Rule 62-212.400, F.A.C.). The allowable emission limitations/standards of the pollutants with significant emissions rate increases will be established by a Best Available Control Technology (BACT) determination (Rule 62-212.410, F.A.C.). The proposed emission unit is also subject to the applicable requirements of the federal Standards of Performance for New Stationary Sources (NSPS) for Gas Turbines, 40 CFR 60, Subpart GG, adopted by reference pursuant to Rule 62-296.800, F.A.C.

The proposed emission unit shall be in compliance with all applicable provisions of Chapters 62-212 through 297 and 62-4, F.A.C., and the 40 CFR 60 (July, 1993 version). The proposed emission unit shall be in compliance with all applicable provisions of Rules 62-210.650, F.A.C.: Circumvention; 62-210.700, F.A.C.: Excess Emissions; 62-296.800, F.A.C.: NSPS; Chapter 62-297, F.A.C.: Stationary Sources - Emissions Monitoring; and, 62-4.130, F.A.C.: Plant Operation - Problems.

V. SOURCE IMPACT ANALYSIS

The proposed 74 MW simple cycle CT will be capable of burning either natural gas or No. 2 fuel oil and will use dry low NO_X combustion technology or water injection, respectively, to control NO_X emissions; and, good combustion practices for VOC and CO control. The SO_2 and the H_2SO_4 mist emissions will be controlled by the use of low sulfur fuel oil (max. 0.05% sulfur content, by weight). Compliance with the BACT SO_2 emission standard will be demonstrated by fuel analysis. The PM_{10} BACT emissions standard/limitation is met through filtering the combustion air, good combustion practices, the use of natural gas and limited low sulfur fuel oil firing.

V.1 **Emission Limitations**

The operation of this emissions unit burning distillate fuel oil or natural gas will produce emissions of NO_X, SO_2, CO, VOC, H_2SO_4, PM/PM_{10}, As, Fluorides, Be, Pb and Hg. Table 1 lists each pollutant subject to an emission limit and its allowable emission rates. Table 2 summarizes the potential emissions of pollutants not subject to a BACT determination.

TABLE 1. MAXIMUM ALLOWABLE EMISSION LIMITS

POLLUTANT	FUEL	BACT STANDARD	LBS/HR[1]	TPY
NO_x	Gas	15 ppmvd @ 15% Oxygen	58	113[2]
	Oil	42 ppmvd @ 15% Oxygen	184	184[3]
			Combined[4]	239
PM_{10}	Gas	Good combustion; visible emissions shall not exceed 10% opacity	7[5]	14[2, 5]
	Oil	Good combustion of low sulfur oil; visible emissions shall not exceed 10% opacity	15[5]	15[3,5]
			Combined[4]	22
SO_2	Gas	Good combustion	29[5]	57[2,5]
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	53[5]	53[3,5]
			Combined[4]	81
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		
H_2SO_4 Mist	Gas	Good combustion	3[5]	6[2,5]
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	6[5]	6[3,5]
			Combined[4]	9
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		

1. These values are calculated using F-factors.
2. Based on a maximum of 3900 hours of operation with natural gas firing.
3. Based on a maximum of 2000 hours of operation with fuel oil firing.
4. Based on 1900 hours natural gas firing and 2000 hours of operation with fuel oil firing.
5. Compliance shall be demonstrated through fuel sulfur analysis.

TABLE 2. ESTIMATED POTENTIAL EMISSIONS

POLLUTANT	METHOD OF CONTROL	TPY[6]
CO	Good combustion, proper use of water injection system	95.4
VOC	Good combustion	8.9
Inorganic Arsenic	Natural Gas/No. 2 Fuel Oil	0
Mercury	Natural Gas/No. 2 Fuel Oil	0.001
Pb	Natural Gas/No. 2 Fuel Oil	0.0638
Be	Natural Gas/No. 2 Fuel Oil	0.00033

6. TPY values are for annual operation reports (AOR) and PSD applicability determinations. These values are based on the DHCT3 operating at full load at ISO for a total of 3900 hours per year, with up to 2000 hours of No. 2 fuel oil-fired operation.

V.2 Air Quality Report

a. Introduction

The proposed project will emit four pollutants in PSD significant amounts. These pollutants are NO_x, SO_2, and PM_{10}, along with the non-criteria pollutant H_2SO_4 mist.

The air quality impact analyses required by the PSD regulations for these pollutants include:

* An analysis of existing air quality;
* A PSD increment analysis (SO_2 and NO_2);
* An Ambient Air Quality Standards (AAQS) analysis;
* An analysis of impacts on soils, vegetation, and visibility and of growth-related air quality modeling impacts; and
* A "Good Engineering Practice" (GEP) stack height determination.

The analysis of existing air quality generally relies on preconstruction monitoring data collected with EPA-approved methods. The PSD increment and AAQS analyses depend on air quality dispersion modeling carried out in accordance with EPA guidelines.

Based on the required analyses, the Department has reasonable assurance that the proposed project, as described in this report and subject to the conditions of approval proposed herein, will not cause or contribute to a violation of any AAQS or PSD increment. However, the following EPA-directed stack height language is included: "In approving this permit, the Florida Department of Environmental Protection has determined that the application complies with the applicable provisions of the stack height regulations as revised by EPA on July 8, 1985 (50 FR 27892). Portions of the regulations have been remanded by a panel of the U.S. Court of Appeals for the D.C. Circuit in NRDC v. Thomas, 838 F. 2d 1224 (D.C. Cir. 1988). Consequently, this permit may be subject to modification if and when EPA revises the regulation in response to the court decision. This may result in revised emission limitations or may affect other actions taken by the source owners or operators." A discussion of the general modeling approach and required analyses follows.

b. Analysis of Existing Air Quality and Determination of Background Concentrations

Preconstruction ambient air quality monitoring is required for all pollutants subject to PSD review. However, an exemption to the monitoring requirement can be obtained if the maximum air quality impact resulting from the projected emissions increase, as determined by air quality modeling, is less than a pollutant-specific de minimus concentration. Pollutants which do not have a specified de minimus level may also be exempt from preconstruction monitoring requirements. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

Even if preconstruction ambient monitoring is exempted, determination of background concentrations for PSD significant pollutants may be necessary for use in the AAQS analysis for each pollutant. These concentrations may be established from the required preconstruction ambient air quality monitoring analysis or from previously existing representative monitoring data. These background ambient air quality concentrations are added to pollutant impacts predicted by modeling and represent the air quality impacts of emissions units not included in the modeling.

Table 3 shows that NO_2, SO_2, and PM_{10} impacts from the project are predicted to be less than the de minimus concentrations. Therefore, preconstruction ambient air quality monitoring is not required for these three pollutants. There are no monitoring de minimus concentrations for H_2SO_4 mist; therefore, no preconstruction monitoring is necessary for this pollutant.

Furthermore, the results presented later in the significant impact analysis section of this air quality report show that NO_2, SO_2, and PM_{10} impacts from this project are not predicted to be greater than the significant impact levels; therefore, no AAQS analyses are required for these pollutants and no background concentrations need to be determined for this project.

c. Air Quality Modeling Approach

The EPA-approved Industrial Source Complex Short-Term (ISCST2) dispersion model was used to evaluate the pollutant emissions from the proposed emissions unit and other existing major facilities. The model determines ground-level concentrations of inert gases or small particles emitted into the atmosphere by point, area and volume sources. The model incorporates elements for plume rise, transport by the mean wind, Gaussian dispersion, and pollutant removal mechanisms such as deposition. The ISCST2 model allows for the separation of emissions units, building wake downwash, and various other input and output features. A series of specific model features, recommended by the EPA, are referred to as the regulatory options. The applicant used the EPA-recommended regulatory options in each modeling scenario. Direction-specific downwash parameters were used for all emissions units for which downwash was considered.

Table 3. Maximum Air Quality Impacts for Comparison to the De Minimus Concentrations.

Pollutant	Avg. Time	Predicted Impact (ug/m^3)	De Minimus Conc. (ug/m^3)
NO_2	Annual	0.02	14
SO_2	24-hour	1.5	13
PM_{10}	24-hour	0.1	10

Table 4. Significant Impact Analysis

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3)	Significant Impact Level (ug/m^3)
NO_2	Annual	0.02	1
SO_2	Annual	0.02	1
	24-hour	1.48	5
	3-hour	4.16	25
PM_{10}	Annual	0.002	1
	24-hour	0.1	5

Initially, the applicant conducted preliminary modeling for the purpose of determining the worst case fuel/load/temperature scenarios for the proposed CT. These modeling runs were conducted using one year of meteorology (1988) at three ambient temperatures (95°F, 75°F, and 20°F) and three CT loads (100%, 80%, and 60%) for both natural gas and distillate fuel oil. In addition, a modeling run was conducted for the CT power augmentation mode at 95°F and 100% load. As a result of these preliminary runs, the applicant determined that there were four different temperature and load combinations which caused the "worst case" ground-level ambient air quality impacts for the different averaging periods and pollutants. These "worst case" conditions were used as input in the significant impact analysis. Maximum predicted concentrations from the proposed project alone were predicted at 900 receptors located in a radial grid centered on the proposed combustion turbine. Receptors were established in 25 concentric rings located at the following distances from the proposed CT: 1.0, 1.5, 2.0, 2.5, 3.0, 3.5, 4.0, 4.5, 5.0, 5.5, 6.0, 7.0, 8.0, 9.0, 10.0, 11.0, 12.0, 13.0, 14.0, 15.0, 16.0, 17.0, 18.0, 19.0, and 20.0 km. Each ring contained 36 receptors spaced at 10-degree intervals. Receptors from these polar grids which fell within the project site boundaries were not included in the analysis; however, 26 additional receptors were placed around the site boundary. In addition, receptors were placed around the perimeter of the Alachua County Public Works facility located within the project site boundary and at a security officer's residence which is also located within the site boundary. Based on the results from the significant impact analysis, no further AAQS or PSD Class II modeling analyses were required.

There are two PSD Class I areas located near this emissions unit, the Chassahowitzka National Wilderness Area (CWNA) and the Okefenokee National Wilderness Area (OWNA). The CWNA is located 110 to 129 km south of the project site while the OWNA is located 90 to 145 km north of the site. In the PSD Class I analysis, the CWNA is represented by 13 Department-approved standard discrete receptors and the OWNA by 10 Department-approved standard discrete receptors.

Meteorological data used in the ISCST2 model to determine air quality impacts consisted of a concurrent 5-year period (1985-1989) of hourly surface weather observations from the National Weather Service (NWS) station at the Gainesville Regional Airport and twice-daily upper air soundings from the NWS station at Tampa (Ruskin). The surface observations included wind direction, wind speed, temperature, cloud cover and cloud ceiling.

Since five years of data were used, the highest-second-high (HSH) short-term predicted concentrations were compared with the appropriate ambient air quality standards or PSD increments. For the annual averages, the highest predicted yearly average was compared with the standards. For determining the significant impact area, if any, both the highest short-term predicted concentrations and the highest predicted yearly averages were compared to the significant impact levels.

d. Significant Impact Analysis

As shown in Table 4, the maximum predicted air quality impacts due to NO_x, SO_2, and PM_{10} emissions from the proposed project are less than the respective significant impact levels for these pollutants. Therefore no further AAQS or PSD Class II modeling analyses were required.

e. PSD Class I Increment Analysis

A proposed emissions unit subject to PSD review must conduct a dispersion modeling analysis of its impacts on any PSD Class I areas located near the source. There are two PSD Class I areas located near this emissions unit, as discussed in the air quality modeling approach section. The modeling results for these two areas are summarized in Table 5. As indicated in this table, the maximum predicted impacts of NO_2, SO_2, and PM_{10} are all below the respective National Park Service significant impact levels. Consequently, the impacts of the proposed project will be well below the applicable PSD Class I increments for these pollutants.

f. Air Toxics Analysis

The maximum impacts of regulated and non-regulated toxic air pollutants that will be emitted by this proposed project are presented in Table 6. Each pollutant's maximum 8-hour, 24-hour, and annual impact is compared to the Acceptable Ambient Concentrations (AAC). The table shows that all toxic pollutant impacts will be below their respective AACs.

V.3 Additional Impacts Analysis

a. Impacts on Soils, Vegetation, and Wildlife

The maximum predicted ground-level concentrations due to NO_x, SO_2, and PM_{10} emissions from the proposed project are less than the PSD significant impact levels. As such, this project is not expected to have a harmful impact on soils, vegetation, and wildlife in the PSD Class II area. In addition, no significant impacts are expected in the two nearby PSD Class I areas.

b. Impact on Visibility

Visual Impact Screening and Analysis (VISCREEN), the EPA-approved Level I visibility computer model was used to estimate the impact of the proposed project's stack emissions on visibility in the CWNA and OWNA PSD Class I areas.

Table 5. PSD Class I Increment Analysis

Pollutant	Averaging Time	Max. Predicted Impact (ug/m^3) CWNA	Max. Predicted Impact (ug/m^3) OWNA	National Park Service Significant Impact Level (ug/m^3)
NO_2	Annual	0.0047	0.0047	0.025
SO_2	Annual	0.00182	0.00182	0.025
	24-hour	0.063	0.068	0.07
	3-hour	0.303	0.267	0.48
PM_{10}	Annual	0.0003	0.0003	0.08
	24-hour	0.018	0.019	0.33

Table 6. Air Toxics Analysis

	8- hour		24- hour		Annual	
Pollutant	Impact (ug/m^3)	AAC (ug/m^3)	Impact (ug/m^3)	AAC (ug/m^3)	Impact (ug/m^3)	AAC (ug/m^3)
Antimony	0.0004	5	0.0002	1.2	0.000002	0.3
Arsenic	0.00009	2	0.00004	0.48	0.0000005	0.000230
Beryllium	0.000006	0.02	0.000003	0.0048	0.00000003	0.00042
Cadmium	0.00008	0.5	0.00004	0.12	0.0000004	0.00056
Chromium+6	0.0009	0.5	0.0004	0.12	0.000005	0.000083
Cobalt	0.0002	0.5	0.00008	0.12	-	-
Formaldehyde	0.078	12	0.035	2.88	0.0008	0.077
Lead	0.001	0.5	0.0005	0.12	0.000006	0.09
Manganese	0.006	50	0.003	12	-	-
Mercury	0.00002	0.5	0.000008	0.12	0.00000009	0.3
Nickel	0.023	0.5	0.011	0.12	0.0002	0.0042
Selenium	0.00001	2	0.000004	0.48	-	-

Note: AAC = Acceptable Ambient Concentration

The results indicate that the maximum visibility impacts caused by the proposed emissions unit do not exceed the screening criteria inside or outside the CWNA and OWNA Class I areas. As a result, there is no significant impact on visibility predicted for either Class I area.

c. Growth-Related Air Quality Impacts

There will be a small number of temporary construction workers during construction. However, there will be no significant impacts on air quality caused by associated population growth.

d. GEP Stack Height Determination

Good Engineering Practice (GEP) stack height means the greater of: (1) 65 m (213 ft); or, (2) the maximum nearby building height plus 1.5 times the building height or width, whichever is less.

The CT structure is the most significant structure associated with the proposed project. The GEP stack height calculated for the CT stack is 38m. The proposed stack height for the CT is 15.8 m; therefore, the CT stack will not exceed the GEP stack height.

VI. CONCLUSION

Based on the information provided by Gainesville Regional Utilities, the Department has reasonable assurance that the proposed installation of the 74 MW simple cycle CT, as described in this evaluation, and subject to the conditions proposed herein, will not cause or contribute to a violation of any air quality standard, PSD increment, or any other technical provision of Chapters 62-212 and 62-4 of the Florida Administrative Code.

John Brown Jr.
Dec 15 1994

Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

PERMITTEE:
Gainesville Regional Utilities
P. O. Box 147117, Station A-134
Gainesville, FL 32614-7117

Permit Number: PSD-FL-212
Expiration Date: June 30, 1996
County: Alachua
Latitude/Longitude: 29°45'32"N
82°23'26"W
Project: A 74 MW Simple Cycle Combustion Turbine (DHCT3)

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.); Chapters 62-210 through 62-297 and 62-4, Florida Administrative Code (F.A.C.); and, 40 CFR 52.21 and 60. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawings, plans, and other documents attached hereto or on file with the Department of Environmental Protection (Department) and specifically described as follows:

Construction of a 74 MW simple cycle combustion turbine designed to burn natural gas and No. 2 fuel oil. Deerhaven combustion turbine (DHCT3) will be constructed/installed at the Gainesville Regional Utilities (GRU)'s existing facility that is located near U.S. 441/SR20/SR25. The UTM coordinates are Zone 17, 365.5 km East and 3292.7 km North.

The emissions unit shall be constructed in accordance with the permit application, plans, documents, amendments and drawings, except as otherwise noted in the General and Specific Conditions.

Attachments are listed below:
1. GRU's letter received October 20, 1993.
2. GRU's letter received December 29, 1993.
3. Construction Permit application received March 22, 1994.
4. Department's letter dated April 22, 1994.
5. GRU's letter with attachments received April 25, 1994.
6. GRU's letter with attachments received August 12, 1994.
7. GRU's letter with attachments received September 21, 1994.
8. Technical Evaluation and Preliminary Determination dated December 16, 1994.

GENERAL CONDITIONS:

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

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

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

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

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

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

7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a

GENERAL CONDITIONS:

reasonable time, access to the premises, where the permitted activity is located or conducted to:

a. Have access to and copy any records that must be kept under the conditions of the permit;

b. Inspect the facility, equipment, practices, or operations regulated or required under this permit; and,

c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

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

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

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

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

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

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

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

11. This permit is transferable only upon Department approval in accordance with Rules 62-4.120 and 62-30.300, F.A.C., as applicable.

GENERAL CONDITIONS:

The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.

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

13. This permit also constitutes:

    (x) Determination of Best Available Control Technology (BACT)
    (x) Determination of Prevention of Significant Deterioration (PSD)
    (x) Compliance with New Source Performance Standards (NSPS)

14. The permittee shall comply with the following:

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

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

    c. Records of monitoring information shall include:

        - the date, exact place, and time of sampling or measurements;
        - the person responsible for performing the sampling or measurements;
        - the dates analyses were performed;
        - the person responsible for performing the analyses;
        - the analytical techniques or methods used; and,
        - the results of such analyses.

15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee

GENERAL CONDITIONS:

becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

SPECIFIC CONDITIONS:

General Operating Requirements

1. The maximum heat input rates, based on high heating values of each fuel, to the DHCT3 and at ISO conditions (i.e., 59° F, 60% relative humidity and 101.3 kilopascals pressure), shall not exceed 971.1 MMBTU/hr, while firing natural gas, nor 990.6 MMBTU/hr, while firing fuel oil. Heat input will vary depending on ambient conditions and the DHCT3 characteristics. Manufacturer's curves or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) at least 90 days before initial compliance testing.

2. The DHCT3 is allowed to operate up to 3900 hours per year, but not to exceed 2000 hours while firing fuel oil.

3. Only natural gas (NG) or No. 2 fuel oil shall be fired in the combustion turbine. The maximum sulfur content of the fuel oil shall not exceed 0.05 percent, by weight. GRU has established that there is approximately 55 hours of full load operation of fuel oil, which contains nominally 0.25% sulfur content, by weight, remaining in the fuel storage tank. GRU will be allowed to deplete this reserve by firing the fuel oil in the DHCT3. However, all future deliveries of fuel oil for the DHCT3 shall meet the BACT requirement, which limits the fuel oil sulfur content to no more than 0.05%, by weight. Fuel sulfur content shall be determined and recorded each time fuel is transferred into the bulk storage tank(s).

4. 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 pursuant to Rule 62-296.310(3), F.A.C. - Unconfined Emissions of Particulate Matter.

5. Any change in the method of operation, equipment or operating hours, pursuant to Rule 62-212.200, F.A.C., Definitions - Modifications, shall be submitted in writing and/or on an application to the DEP's Bureau of Air Regulation office and Northeast District office.

SPECIFIC CONDITIONS:

Emission Limits

6. The maximum allowable emissions from the DHCT3, when firing natural gas or No. 2 fuel oil, in accordance with the BACT determination, and at 95 - 100% percent load based on the manufacturer's curves submitted to the DEP, shall not exceed the following limits except during periods of start up, shutdown, and malfunction pursuant to Rule 62-210.700, F.A.C.:

MAXIMUM ALLOWABLE EMISSION LIMITS

POLLUTANT	FUEL	BACT STANDARD	LBS/HR *	TPY
NO_x	Gas	15 ppmvd @ 15% Oxygen	58	113(a)
	Oil	42 ppmvd @ 15% Oxygen	184	184(b)
			Combined(c)	239
PM_{10}	Gas	Good combustion; visible emissions shall not exceed 10% opacity	7(d)	14(a)(d)
	Oil	Good combustion of low sulfur oil; visible emissions shall not to exceed 10% opacity	15(d)	15(b)(d)
			Combined(c)	22
SO_2	Gas	Good combustion	29(d)	57(a)(d)
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	53(d)	53(b)(d)
			Combined(c)	81
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		
H_2SO_4 Mist	Gas	Good combustion	3(d)	6(a)(d)
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	6(d)	6(b)(d)
			Combined(c)	9
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		

*These values are calculated using F factors.
(a) Based on a maximum of 3900 hours of operation with natural gas firing.
(b) Based on a maximum of 2000 hours of operation with fuel oil firing.
(c) Based on 1900 hours natural gas firing and 2000 hours of operation with fuel oil firing.
(d) Compliance shall be demonstrated through fuel sulfur analysis.

SPECIFIC CONDITIONS:

7. Visible emissions shall not exceed 10% opacity when firing natural gas or No. 2 fuel oil.

8. The potential emissions projected from the DHCT3 are:

ESTIMATED POTENTIAL EMISSIONS

Pollutant	Method of Control	TPY **
CO	Good combustion, proper use of water injection system	95.4
VOC	Good combustion	8.9
Inorganic Arsenic	Natural Gas/No. 2 Fuel Oil	0
Mercury	Natural Gas/No. 2 Fuel Oil	0.001
Pb	Natural Gas/No. 2 Fuel Oil	0.0638
Be	Natural Gas/No. 2 Fuel Oil	0.00033

** TPY values are for annual operation reports (AOR) and PSD applicability determinations. These values are based on the DHCT3 operating at full load at ISO for a total of 3900 hours per year, with up to 2000 hours of No. 2 fuel oil-fired operation.

Compliance Determination

9. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate at which this unit will be operated, but not later than 180 days of initial operation at the maximum capability of the unit and annually thereafter, by using the following reference methods as described in 40 CFR 60, Appendix A (1993 version), and adopted by reference in Chapter 62-297, F.A.C.

Initial (I) compliance tests shall be performed on the DHCT3 while firing each fuel (gas, oil). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.340, F.A.C., on the DHCT3 with the fuel(s) used for more than 400 hours in the preceding 12-month period.

- Method 9 Visual Determination of the Opacity of Emissions from Stationary Sources (I,A)

SPECIFIC CONDITIONS:

- Method 10 Determination of Carbon Monoxide Emissions from Stationary Sources (I)

- Method 20 Determination of Nitrogen Oxides and Diluent Emissions from Stationary Gas Turbines (I,A)

Note: No other methods may be used for compliance testing unless prior DEP approval is received in writing. The DEP may request a special compliance test pursuant to Rule 62-297.340(2), 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.

10. Notwithstanding the requirements of Rule 62-297.340, F.A.C., the exclusive use of fuel oil with a maximum sulfur content limit of 0.05% or less, by weight, is the method for determining compliance for SO_2, H_2SO_4 mist, and PM_{10}. There is no suitable method for the testing of PM_{10} from this type of emissions unit, and the SO_2 and H_2SO_4 emissions are clearly limited by the sulfur content of the fuel. Compliance with the SO_2 and sulfuric acid mist emission limits shall be determined by fuel oil analysis using ASTM D2880-71 or D4294 (or equivalent) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel. Alternatively, natural gas supplier data for sulfur content may be submitted. However, the applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. 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) (1993 version).

11. Pursuant to Rule 62-212.410, F.A.C., the permittee shall install a dry low-NO_x combustor on the DHCT3 for NO_x control when firing natural gas. Control of NO_x when firing No. 2 fuel oil shall be accomplished by water injection.

12. An initial test for CO, concurrent with each NO_x test, is required to confirm that annual potential emissions will not exceed 100 TPY. The NOx and initial CO test results shall be the average of three valid one-hour runs. The DEP's Northeast District office shall be notified, in writing, at least 30 days prior to the initial compliance tests and at least 15 days before annual compliance test(s). The combustion turbine shall operate between 95% and 100% of maximum capacity for the ambient conditions experienced during compliance test(s). The turbine manufacturer's heat input rates (based on the high heating value of the fuel) vs. ambient temperature curve shall be included with the compliance

SPECIFIC CONDITIONS:

test results. The fuel feed rates and the high heating value of the fuels shall be established during the initial and annual compliance tests. Compliance test results shall be submitted to the DEP's Northeast District office no later than 45 days after completion of the last test run.

13. Excess NO_x emissions from this turbine resulting from startup, shutdown, malfunction, fuel switching or load change, shall be acceptable providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the DEP's Bureau of Air Regulation or the Northeast District office for a longer duration. Best operating practices shall be documented in writing and a copy submitted to the DEP's Northeast District office along with the initial compliance test data. The document may be updated as needed with all updates submitted to the DEP's Northeast District office within thirty (30) days of implementation and shall include time limitations on excess emissions caused by turbine startup.

Notification, Reporting and Recordkeeping

14. Notification and recordkeeping shall be in accordance with 40 CFR 60.7 (1993 version). The following protocols shall be submitted to the DEP's Northeast District office for approval:

a. CEMS - If applicable, the Federal Acid Rain Program requirements of 40 CFR 75 shall apply when those requirements become effective in Florida.

b. Performance Test Protocol - At least 30 days prior to conducting the initial performance tests required by this permit, the permittee shall submit to the DEP's Northeast District office for their review and approval: a protocol outlining the procedures to be followed; the test methods; and, any differences between the reference methods and the test methods proposed to be used to verify compliance with the conditions of this permit.

c. All measurements, records, and other data required to be maintained by GRU shall be retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These data shall be made available to the DEP representatives.

Monitoring Requirements

15. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the

SPECIFIC CONDITIONS:

nitrogen oxides emissions from this source. One-hour periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards (15/42 gas/oil) shall be reported as excess emissions following the format of 40 CFR 60.7 (1993 version). The continuous emission monitor must comply with Rule 62-297.500, F.A.C.; 40 CFR 60, Appendix F, Quality Assurance Procedures (1993 version) (or other DEP approved QA plan); 40 CFR 60, Appendix B, Performance Specification 2 (1993 version); or, if applicable, 40 CFR 75, Appendix A and Appendix B. Periods of startup, shutdown, fuel switching, malfunction, and load change shall be monitored and recorded. The NO_X CEMS will be used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring, which are required in accordance with 40 CFR 60, Subpart GG (1993 version), and are used as indicators of compliance with the NO_X standard specified in the subpart. Since the NO_X emission standard from Subpart GG is more than twice the BACT standard, monitoring for emissions in excess of the BACT limits using the NO_X CEMS is more stringent. FBN levels are not required for excess emission reports when excess emissions are reported and based on the stack monitoring system. The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) (1993 version) will be replaced by certification tests of the NO_X CEMS.

16. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions and shall be prohibited pursuant to Rule 62-210.700, F.A.C.

17. The sulfur content of the fuel oil being fired in the combustion turbine shall be determined in accordance with 40 CFR 60.334(b) (1993 version). Any request for a future custom monitoring schedule shall be made in writing and directed to the DEP's Bureau of Air Regulation office. Any custom schedule approved by the DEP pursuant to 40 CFR 60.334(b) (1993 version) will be recognized as enforceable provisions of the permit, provided that the holder of this permit demonstrates that the provisions of the schedule will be adequate to assure continuous compliance. The records of natural gas and No. 2 fuel oil usage shall be kept by the company for a five-year period for regulatory agency inspection purposes.

<u>**Rule Requirements**</u>

18. The emission unit shall be in compliance with all applicable provisions of Chapter 403, F.S., and Chapters 62-4, 210, 212, 275, 296 and 297, F.A.C.

SPECIFIC CONDITIONS:

19. The emission unit shall be in compliance with all applicable requirements of 40 CFR 60, Subpart A, Appendix A and Appendix B (1993 version), Subpart GG - Standards of Performance for Stationary Gas Turbines (1993 version), and Rule 62-296.800(2)(a), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). All notifications and reports required by this specific condition shall be submitted to the DEP's Northeast District office.

20. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (Rule 62-210.300(1), F.A.C.).

21. The emission unit shall be in compliance with all applicable provisions of Rule 62-210.650, F.A.C.: Circumvention; Rule 62-210.700, F.A.C.: Excess Emissions; Rule 62-296.800, F.A.C.: Standards of Performance for New Stationary Sources (NSPS); Chapter 62-297, F.A.C.: Stationary Sources - Emissions Monitoring; and, Rule 62-4.130, F.A.C.: Plant Operation - Problems.

22. If construction does not commence within 18 months of issuance of this permit, the permittee shall obtain from the DEP's Bureau of Air Regulation a review and, if necessary, a modification of the BACT determination and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2) (1993 version)).

23. Quarterly excess emission reports, in accordance with 40 CFR 60.7 and 60.334 (1993 version), shall be submitted to the DEP's Northeast District office.

24. Pursuant to Rule 62-210.370(2), F.A.C., Annual Operating Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur content of the fuel being fired, fuel usage, hours of operation, air emissions limits, etc. Annual operating reports shall be sent to the DEP's Northeast District office by March 1st of each calendar year.

25. Stack sampling facilities shall be installed in accordance with Rule 62-297.345, F.A.C.

26. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (Rule 62-4.090, F.A.C.).

SPECIFIC CONDITIONS:

27. An application for an operation permit must be submitted to the Northeast District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the permittee shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (Rules 62-4.055 and 62-4.220, F.A.C.).

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Virginia B. Wetherell
Secretary

Best Available Control Technology (BACT) Determination
Gainesville Regional Utilities
Alachua County

PSD-FL-212

Gainesville Regional Utilities (GRU) proposes to construct a 74 MW (nominal) simple cycle combustion turbine (CT) at the existing Deerhaven site approximately seven miles north of Gainesville in Alachua County. The selected CT, designated as DHCT3, is a GE Model MS 7001 EA with dry low-NO_X combustors and will also use water injection for NO_X control when firing fuel oil.

The applicant requested approval to operate the emission unit for 3900 hours per year, as indicated in the table below. The No. 2 fuel oil will have a maximum limit of 0.05 percent sulfur content, by weight. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the combustion turbine at 100 percent load, at 15% O_2 and ISO conditions (59°F, 60% relative humidity, and 101.3 kilopascals pressure), for each type of fuel fired, to be as follows:

Pollutant	Emissions (TPY) Gas	Gas w/PA *	Oil	Total	PSD Significant Emission Rate (TPY)
	1510 Hrs	390 Hrs	2000 Hrs		
NO_X	40	23	213	276	40
SO_2	20	6	48	74	40
PM/PM_{10}	5	1	15	21	25/15
CO	24	8	65	97	100
VOC	2	1	6	9	40
H_2SO_4 mist	2	1	5	8	7
Be			0.00033	0.00033	0.0004
Hg			0.001	0.001	0.1
Pb			0.0638	0.0638	0.6
As			0	0	0

* with power augmentation

Rule 62-212.400(2)(f)(1), Florida Administrative Code (F.A.C.), requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the table above. Therefore, BACT is required for NO_X, SO_2, PM_{10}, and H_2SO_4 mist.

<u>Date of Receipt of a BACT Application</u>

March 25, 1994

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	15 ppmvd @ 15% O_2 (natural gas firing) 54 ppmvd @ 15% O_2 (for No. 2 fuel oil firing), maximum based on fuel bound nitrogen 30 ppmvd @ 15% O_2 (natural gas firing-power augmentation mode). Dry low-NOx combustor when firing natural gas and water injection when firing distillate oil and during power augmentation mode.
PM_{10}	Prefiltering of the combustion air, good combustion practices, and use of natural gas as the primary fuel with limited annual fuel oil firing.
SO_2	0.05% sulfur content by weight (fuel oil firing); also, an equivalent of up to 55 hours of full load operation at ISO conditions using a fuel oil with a maximum of 0.25% sulfur content, by weight.
H_2SO_4 Mist	0.05% sulfur by weight (fuel oil firing), also, an equivalent of up to 55 hours of full load operation at ISO conditions using a fuel oil with a maximum of 0.25% sulfur content, by weight.

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:

(a) 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).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determination of any other state.

(d) 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 infeasible 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 air pollutant emissions from simple cycle combustion turbines can be grouped into categories based upon the control equipment and techniques that are available to control emissions from these emission units. Using this approach, the emissions can be classified as follows:

- Combustion Products (e.g., particulate matter). Controlled generally by good combustion of clean fuels.

- Products of Incomplete Combustion (e.g., carbon monoxide). Control is largely achieved by proper combustion techniques.

- Acid Gases (e.g., nitrogen oxides). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulate matter, sulfur dioxide, fluorides, sulfuric acid mist, etc,), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

ACID GASES

Nitrogen Oxides (NOx)

The emissions of nitrogen oxides represent a significant portion of the total emissions generated by this project, and need to be controlled as deemed appropriate. As such, the applicant presented an extensive analysis of the different available technologies for NO_x control.

The applicant stated that BACT for nitrogen oxides will be met by using dry low-NO_x combustor design to limit emissions to 15 ppmvd (corrected to 15% O_2), when burning natural gas; and, by water injection to limit emissions to the applicant's proposed BACT level of up to 54 ppmvd (corrected to 15% O_2), when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NO_x emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system on two 25 MW combustion turbines located in Kern County, California.

SCR is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction efficiency (while holding ammonia slip emissions constant) will decrease.

The effect of exhaust gas temperature on NOx reduction depends on the specific catalyst formulation and reactor design. Generally, SCR units can be designed to achieve effective NOx control over a 100-300°F operating window within the bounds of 450-800°F, although recently developed zeolite-based catalysts are claimed to be capable of operating at temperatures as high as 950°F.

Most commercial SCR systems operate over a temperature range of about 600-750°F. At levels above and below this window, the specific catalyst formulation will not be effective and NO_x reduction will decrease. Operating at high temperatures can permanently damage the catalyst through sintering of surfaces.

Increased water vapor content in the exhaust gas (as would result from water or steam injection in the gas turbine combustor) can shift the operating temperature window of the SCR reactor to slightly higher levels.

The exhaust temperatures of the proposed simple cycle CT for this site will range from 955°F to 1,100°F. At temperatures of 1,100°F and above, the zeolite catalyst (reported to operate to a maximum temperature of 1,050°F) will be irreparably damaged.

Based on the GE data sheets for the proposed DHCT3 provided by the applicant, exhaust temperatures will range from 955°F to 1,100°F, depending upon the fuel fired, ambient temperature and load. Since the zeolite catalysts were reported to operate in this temperature range, ENSERCH Environmental investigated the technical feasibility of using such a system. Because the zeolite catalysts are new, only one vendor (Norton Chemical Process Products Corporation, P.O.

Box 350, Akron, Ohio 44309-0350) was capable of providing a cost estimate. A second vendor was contacted and a cost estimate was requested, but no response was received. This cost estimate noted that the current zeolite catalyst is limited to a maximum upper temperature of 1,050°F and, without an air injection system to cool the exhaust gases at the zeolite catalyst, its use would be infeasible. Review of the GE data sheets for the Deerhaven CT confirmed the vendor's exhaust gas temperature findings. ENSERCH Environmental requested that the vendor revise the initial cost estimate and include the cost of an air injection system.

Based on the information obtained from the vendor, the use of a SCR system equipped with a zeolite catalyst and an air injection system was deemed to be only potentially technically feasible based upon its limited usage on simple cycle CTs. In addition, although the concept of an air injection system is easily visualized, its use commercially has been documented only once in the clearinghouse as a commercially available response to the temperature limitations of SCR. Although only potentially technically feasible, ENSERCH Environmental evaluated the impacts of a SCR system equipped with a high temperature zeolite catalyst and an air injection system as the available post-combustion control technology needed to meet the most stringent emission limitations.

For the simple cycle combustion turbine and based on the information supplied by the applicant, it is estimated that the maximum annual NO_X emissions using a low-NO_X combustor will be 276.42 tons/year. Assuming that SCR would reduce the NO_X emissions by approximately 80%, about 58.22 tons of NO_X would be emitted annually. When this reduction is taken into consideration alone with the total levelized annual operating cost of $1,455,957.33, the incremental cost effectiveness ($/ton) of controlling NO_X is $6,672.58 for this project. These calculated costs are higher than costs previously approved as BACT.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (H_2SO_4)

The applicant stated that the sulfur dioxide (SO_2) and sulfuric acid (H_2SO_4) mist emissions, when firing No. 2 fuel oil, will be controlled by using fuel oil with a maximum sulfur content limit of 0.05%, by weight. This will result in an annual emission rate of 81 tons SO_2 per year and 9 tons H_2SO_4 mist per year (with no power augmentation, operating at 1900 hours per year on natural gas, and operating 2000 hours per year on No. 2 fuel oil with a maximum limit of 0.05% sulfur content, by weight).

In accordance with the "top down" BACT review approach, only two alternatives exist that would result in more stringent SO_2 emissions. These include the use of a lower sulfur content fuel oil or the use of wet lime or limestone-based scrubbers, otherwise known as flue gas desulfurization (FGD).

In developing the NSPS for stationary gas turbines, EPA recognized that FGD technology was inappropriate to apply to these combustion units. EPA acknowledged in the preamble of the proposed NSPS that "Due to the high volumes of exhaust gases, the cost of flue gas desulfurization (FGD) to control SO_2 emission from stationary gas turbines is considered unreasonable." EPA reinforced this point when, later in the preamble, they stated that "FGD...would cost about two to three times as much as the gas turbine." The economic impact of applying FGD today is no different.

Furthermore, the application of FGD would have negative environmental and energy impacts. Sludge would be generated that would have to be disposed of properly and there would be increased utility (electricity and water) costs associated with the operation of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

The elimination of flue gas control as a BACT option leaves the use of low sulfur fuel oil as the next option to be investigated. Gainesville Regional Utilities, as stated above, has proposed the use of No. 2 fuel oil with no more than 0.05% sulfur content, by weight, as BACT for this project.

Particulate Matter (PM) Emissions

Particulate matter (PM) emissions from combustion turbines are related to the combustion air, fuel quality and combustion efficiency. Review of the BACT/LAER Clearinghouse indicates that most combustion turbines meet the BACT requirement through filtering the combustion air, good combustion practices, use of clean burning natural gas and limited fuel oil firing. Currently, post combustion controls (i.e., baghouse) are not being used on combustion turbines. This is due mostly to the characteristics of the exhaust gases (high temperatures and velocities) and the low emissions rates for PM when good combustion of low sulfur fuels is employed.

PM_{10} (PM less than 10 microns in diameter) emissions result from noncombustibles in the fuels, PM_{10} in the ambient air used as combustion air, dissolved solids in the water used for wet injection, and incomplete combustion. Since solids can damage the combustion turbine, considerable efforts are made to limit their entry and/or formation. Based on this need and review of the BACT/LAER Clearinghouse data, the applicant proposes prefiltering of the combustion air, good combustion practices, and use of natural gas as the primary fuel and limited annual fuel oil firing as BACT.

BACT Determination by the Department

NO_x Control

The information that the applicant presented and Department calculations indicate that the cost per ton of controlling NO_x for this turbine [$6,672.58 per ton] is high compared with other BACT determinations, which required SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_x control is not justifiable as BACT.

It is the Department's understanding that General Electric is developing controls using either steam/water injection or dry low-NO_x combustor technology to achieve a NO_x emission control level of 9 ppm when firing natural gas. Several prior CT projects have already been permitted at 15 ppmvd @ 15% O_2 (natural gas) and 42 ppmvd @ 15% O_2 (No. 2 fuel oil). In these BACT determinations, no allowance has been made for fuel bound nitrogen or for operation with power augmentation. The Department has determined that BACT for this project is 15 ppmvd @ 15% O_2 using natural gas and 42 ppmvd @ 15% O_2 when firing No. 2 fuel oil. Measured NO_x concentrations shall not be corrected to ISO conditions to determine compliance with these BACT standards. Based on emission rates at the worst case design ambient conditions (20°F) supplied by GE, NO_x emissions will also be limited to 58 lbs/hr for natural gas firing and 184 lbs/hr for fuel oil firing.

SO_2 and H_2SO_4 Mist Control

The Department accepts the applicant's proposal as BACT for sulfur dioxide and H_2SO_4 mist, which is the burning of either natural gas or No. 2 fuel oil with a maximum limit of 0.05% sulfur content, by weight. Fuel oil usage will be limited to no more than 2000 hours per year. GRU has estimated that there is approximately 55 hours of full load operation of fuel oil at 0.25% sulfur content, by weight, remaining in the fuel oil storage tank. GRU will be allowed to deplete this reserve of fuel oil. However, all future deliveries of fuel oil shall meet the BACT requirements, which is a maximum limit of 0.05% sulfur content, by weight.

PM_{10} Control

The Department accepts the applicant's proposed BACT for this emission unit. PM_{10} emissions from fuel burning are related to the sulfur content of the fuel and combustion practices. PM_{10} emissions will be controlled by good combustion practices and firing natural gas; or, firing No. 2 fuel oil for no more than 2000 hours per year. The No. 2 fuel oil shall be limited to no more than 0.05% sulfur content, by weight. In addition, visible emissions shall not exceed 10% opacity when firing natural gas or fuel oil.

BACT Standards

The BACT emission limits for the Gainesville Regional Utilities project, a DHCT3, are established as follows:

MAXIMUM ALLOWABLE EMISSION LIMITS

POLLUTANT	FUEL	BACT STANDARD	LBS/HR *	TPY
NO_x	Gas	15 ppmvd @ 15% Oxygen	58	113(a)
	Oil	42 ppmvd @ 15% Oxygen	184	184(b)
			Combined(c)	239
PM_{10}	Gas	Good combustion; visible emissions shall not exceed 10% opacity	7(d)	14(a)(d)
	Oil	Good combustion of low sulfur oil; visible emissions shall not to exceed 10% opacity	15(d)	15(b)(d)
			Combined(c)	22
SO_2	Gas	Good combustion	29(d)	57(a)(d)
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	53(d)	53(b)(d)
			Combined(c)	81
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		
H_2SO_4 Mist	Gas	Good combustion	3(d)	6(a)(d)
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	6(d)	6(b)(d)
			Combined(c)	9
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		

*These values are calculated using F factors.
(a) Based on a maximum of 3900 hours of operation with natural gas firing.
(b) Based on a maximum of 2000 hours of operation with fuel oil firing.
(c) Based on 1900 hours natural gas firing and 2000 hours of operation with fuel oil firing.
(d) Compliance shall be demonstrated through fuel sulfur analysis.

Monitoring

The BACT emission limitations for NO_x are one-hour averages. Compliance with these standards will be verified by a stack test and excess emissions will be monitored by a stack continuous emissions monitoring system (CEMS) for NO_x and oxygen. The NO_x CEMS will be

used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring which are required in 40 CFR 60, Subpart GG, and which are used as indicators of compliance with the NO_X standard specified in the subpart. Since the NO_X emission standard from Subpart GG is more than twice the BACT standard, monitoring for emissions in excess of the BACT limits using the NO_X CEMS is more stringent. FBN monitoring is not required for excess emission reports when excess emissions are reported based on the stack monitoring system. The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) will be replaced by certification tests of the NO_X and oxygen CEMS.

Details of the Analysis May be Obtained by Contacting:

Martin Costello, BACT Coordinator, P.E.
Department of Environmental Protection
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:

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

____________________, 1995
Date

Approved by:

Virginia B. Wetherell, Secretary
Dept. of Environmental Protection

____________________, 1995
Date

Memorandum

Florida Department of
Environmental Protection

TO : Buck Oven, PPS

FROM: for Clair Fancy JKP

SUBJECT: Gainesville Regional Utilities
PA 74-04/PSD-FL-212

DATE: November 29, 1994

Attached please find a copy of the Conditions of Certification and BACT determination for the GRU Deerhaven Combustion Turbine #3. If you have any questions, please call Bruce Mitchell, Martin Costello or Teresa Heron at (904)488-1344.

Best Available Control Technology (BACT) Determination
Gainesville Regional Utilities
Alachua County

PSD-FL-212

Gainesville Regional Utilities (GRU) proposes to construct a 74 MW (nominal) simple cycle combustion turbine (CT) at the existing Deerhaven site approximately seven miles north of Gainesville in Alachua County. The selected CT, designated as DHCT3, is a GE Model MS 7001 EA with dry low-NO_x combustors and will also use water injection for NO_x control when firing fuel oil.

The applicant requested approval to operate the emission unit for 3900 hours per year, as indicated in the table below. The No. 2 fuel oil will have a maximum limit of 0.05 percent sulfur content, by weight. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the combustion turbine at 100 percent load, at 15% O_2 and ISO conditions (59°F, 60% relative humidity, and 101.3 kilopascals pressure), for each type of fuel fired, to be as follows:

Pollutant	Emissions (TPY) Gas	Gas w/PA *	Oil	Total	PSD Significant Emission Rate (TPY)
	1510 Hrs	390 Hrs	2000 Hrs		
NO_x	40	23	213	276	40
SO_2	20	6	48	74	40
PM/PM_{10}	5	1	15	21	25/15
CO	24	8	65	97	100
VOC	2	1	6	9	40
H_2SO_4 mist	2	1	5	8	7
Be			0.00033	0.00033	0.0004
Hg			0.001	0.001	0.1
Pb			0.0638	0.0638	0.6
As			0	0	0

* with power augmentation

Rule 62-212.400(2)(f)(1), Florida Administrative Code (F.A.C.), requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the table above. Therefore, BACT is required for NO_x, SO_2, PM_{10}, and H_2SO_4 mist.

Date of Receipt of a BACT Application

March 25, 1994

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	15 ppmvd @ 15% O_2 (natural gas firing) 54 ppmvd @ 15% O_2 (for No. 2 fuel oil firing) 30 ppmvd @ 15% O_2 (natural gas firing-power augmentation mode). Dry low-NOx combustor when firing natural gas and water injection when firing distillate oil and during power augmentation mode.
PM_{10}	Prefiltering of the combustion air, good combustion practices, and use of natural gas as the primary fuel with limited annual fuel oil firing.
SO_2	0.05% sulfur content by weight (fuel oil firing); also, an equivalent of up to 55 hours of operation at ISO conditions using a fuel oil with a maximum of 0.25% sulfur content, by weight.
H_2SO_4 Mist	0.05% sulfur by weight (fuel oil firing), also, an equivalent of up to 55 hours of operation at ISO conditions using a fuel oil with a maximum of 0.25% sulfur content, by weight.

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:

(a) 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).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determination of any other state.

(d) 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 infeasible 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 air pollutant emissions from simple cycle combustion turbines can be grouped into categories based upon the control equipment and techniques that are available to control emissions from these emission units. Using this approach, the emissions can be classified as follows:

- o Combustion Products (e.g., particulate matter). Controlled generally by good combustion of clean fuels.
- o Products of Incomplete Combustion (e.g., carbon monoxide). Control is largely achieved by proper combustion techniques.
- o Acid Gases (e.g., nitrogen oxides). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limiting standard as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulate matter, sulfur dioxide, fluorides, sulfuric acid mist, etc,), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

ACID GASES

Nitrogen Oxides (NOx)

The emissions of nitrogen oxides represent a significant portion of the total emissions generated by this project, and need to be controlled as deemed appropriate. As such, the applicant presented an extensive analysis of the different available technologies for NO_x control.

The applicant stated that BACT for nitrogen oxides will be met by using dry low-NO_x combustor design to limit emissions to 15 ppmvd (corrected to 15% O_2), when burning natural gas; and, by water injection to limit emissions to the applicant's proposed BACT level of 54 ppmvd (corrected to 15% O_2), when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NO_x emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system on two 25 MW combustion turbines located in Kern County, California.

SCR is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction efficiency (while holding ammonia slip emissions constant) will decrease.

The effect of exhaust gas temperature on NOx reduction depends on the specific catalyst formulation and reactor design. Generally, SCR units can be designed to achieve effective NOx control over a 100-300°F operating window within the bounds of 450-800°F, although recently developed zeolite-based catalysts are claimed to be capable of operating at temperatures as high as 950°F.

Most commercial SCR systems operate over a temperature range of about 600-750°F. At levels above and below this window, the specific catalyst formulation will not be effective and NO_x reduction will decrease. Operating at high temperatures can permanently damage the catalyst through sintering of surfaces.

Increased water vapor content in the exhaust gas (as would result from water or steam injection in the gas turbine combustor) can shift the operating temperature window of the SCR reactor to slightly higher levels.

The exhaust temperatures of the proposed simple cycle CT for this site will range from 955°F to 1,100°F. At temperatures of 1,100°F and above, the zeolite catalyst (reported to operate to a maximum temperature of 1,050°F) will be irreparably damaged.

Based on the GE data sheets for the proposed DHCT3 provided by the applicant, exhaust temperatures will range from 955°F to 1,100°F, depending upon the fuel fired, ambient temperature and load. Since the zeolite catalysts were reported to operate in this temperature range, ENSERCH Environmental investigated the technical feasibility of using such a system. Because the zeolite catalysts are new, only one vendor (Norton Chemical Process Products Corporation, P.O.

Box 350, Akron, Ohio 44309-0350) was capable of providing a cost estimate. A second vendor was contacted and a cost estimate was requested, but no response was received. This cost estimate noted that the current zeolite catalyst is limited to a maximum upper temperature of 1,050°F and, without an air injection system to cool the exhaust gases at the zeolite catalyst, its use would be infeasible. Review of the GE data sheets for the Deerhaven CT confirmed the vendor's exhaust gas temperature findings. ENSERCH Environmental requested that the vendor revise the initial cost estimate and include the cost of an air injection system.

Based on the information obtained from the vendor, the use of a SCR system equipped with a zeolite catalyst and an air injection system was deemed to be only potentially technically feasible based upon its limited usage on simple cycle CTs. In addition, although the concept of an air injection system is easily visualized, its use commercially has been documented only once in the clearinghouse as a commercially available response to the temperature limitations of SCR. Although only potentially technically feasible, ENSERCH Environmental evaluated the impacts of a SCR system equipped with a high temperature zeolite catalyst and an air injection system as the available post-combustion control technology needed to meet the most stringent emission limitations.

For the simple cycle combustion turbine and based on the information supplied by the applicant, it is estimated that the maximum annual NO_X emissions using a low-NO_X combustor will be 276.42 tons/year. Assuming that SCR would reduce the NO_X emissions by approximately 80%, about 58.22 tons of NO_X would be emitted annually. When this reduction is taken into consideration alone with the total levelized annual operating cost of $1,455,957.33, the incremental cost effectiveness ($/ton) of controlling NO_X is $6,672.58 for this project. These calculated costs are higher than costs previously approved as BACT.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (H_2SO_4)

The applicant stated that the sulfur dioxide (SO_2) and sulfuric acid (H_2SO_4) mist emissions, when firing No. 2 fuel oil, will be controlled by using fuel oil with a maximum sulfur content limit of 0.05%, by weight. This will result in an annual emission rate of 67 tons SO_2 per year and 7.2 tons H_2SO_4 mist per year (with no power augmentation, operating at 1900 hours per year on natural gas, and operating 2000 hours per year on No. 2 fuel oil with a maximum limit of 0.05% sulfur content, by weight).

In accordance with the "top down" BACT review approach, only two alternatives exist that would result in more stringent SO_2 emissions. These include the use of a lower sulfur content fuel oil or the use of wet lime or limestone-based scrubbers, otherwise known as flue gas desulfurization (FGD).

In developing the NSPS for stationary gas turbines, EPA recognized that FGD technology was inappropriate to apply to these combustion units. EPA acknowledged in the preamble of the proposed NSPS that "Due to the high volumes of exhaust gases, the cost of flue gas desulfurization (FGD) to control SO_2 emission from stationary gas turbines is considered unreasonable." EPA reinforced this point when, later in the preamble, they stated that "FGD...would cost about two to three times as much as the gas turbine." The economic impact of applying FGD today is no different.

Furthermore, the application of FGD would have negative environmental and energy impacts. Sludge would be generated that would have to be disposed of properly and there would be increased utility (electricity and water) costs associated with the operation of a FGD system. Finally, there is no information in the literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

The elimination of flue gas control as a BACT option leaves the use of low sulfur fuel oil as the next option to be investigated. Gainesville Regional Utilities, as stated above, has proposed the use of No. 2 fuel oil with no more than 0.05% sulfur content, by weight, as BACT for this project.

Particulate Matter (PM) Emissions

Particulate matter (PM) emissions from combustion turbines are related to the combustion air, fuel quality and combustion efficiency. Review of the BACT/LAER Clearinghouse indicates that most combustion turbines meet the BACT requirement through filtering the combustion air, good combustion practices, use of clean burning natural gas and limited fuel oil firing. Currently, post combustion controls (i.e., baghouse) are not being used on combustion turbines. This is due mostly to the characteristics of the exhaust gases (high temperatures and velocities) and the low emissions rates for PM when good combustion of low sulfur fuels is employed.

PM_{10} (PM less than 10 microns in diameter) emissions result from noncombustibles in the fuels, PM_{10} in the ambient air used as combustion air, dissolved solids in the water used for wet injection, and incomplete combustion. Since solids can damage the combustion turbine, considerable efforts are made to limit their entry and/or formation. Based on this need and review of the BACT/LAER Clearinghouse data, the applicant proposes prefiltering of the combustion air, good combustion practices, and use of natural gas as the primary fuel and limited annual fuel oil firing as BACT.

BACT Determination by the Department

NO_x Control

The information that the applicant presented and Department calculations indicate that the cost per ton of controlling NO_x for this turbine [$6,672.58 per ton] is high compared with other BACT determinations, which required SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_x control is not justifiable as BACT.

It is the Department's understanding that General Electric is developing controls using either steam/water injection or dry low-NO_x combustor technology to achieve a NO_x emission control level of 9 ppm when firing natural gas. Several prior CT projects have already been permitted at 15 ppmvd @ 15% O_2 (natural gas) and 42 ppmvd @ 15% O_2 (No. 2 fuel oil). In these BACT determinations, no allowance has been made for fuel bound nitrogen or for operation with power augmentation. The Department has determined that BACT for this project is 15 ppmvd @ 15% O_2 using natural gas and 42 ppmvd @ 15% O_2 when firing No. 2 fuel oil. Measured NO_x concentrations shall not be corrected to ISO conditions to determine compliance with these BACT standards. Based on emission rates at the worst case design ambient conditions (20°F) supplied by GE, NO_x emissions will also be limited to 58 lbs/hr for natural gas firing and 184 lbs/hr for fuel oil firing.

SO_2 and H_2SO_4 Mist Control

The Department accepts the applicant's proposal as BACT for sulfur dioxide and H_2SO_4 mist, which is the burning of either natural gas or No. 2 fuel oil with a maximum limit of 0.05% sulfur content, by weight. Fuel oil usage will be limited to no more than 2000 hours per year. GRU has estimated that there is approximately 55 hours of full load operation of fuel oil at 0.25% sulfur content, by weight, remaining in the fuel oil storage tank. GRU will be allowed to deplete this reserve of fuel oil. However, all future deliveries of fuel oil shall meet the BACT requirements, which is a maximum limit of 0.05% sulfur content, by weight.

PM_{10} Control

The Department accepts the applicant's proposed BACT for this emission unit. PM_{10} emissions from fuel burning are related to the sulfur content of the fuel and combustion practices. PM_{10} emissions will be controlled by good combustion practices and firing natural gas; or, firing No. 2 fuel oil for no more than 2000 hours per year. The No. 2 fuel oil shall be limited to no more than 0.05% sulfur content, by weight. In addition, visible emissions shall not exceed 10% opacity when firing natural gas or fuel oil.

BACT Standards

The BACT emission limits for the Gainesville Regional Utilities project, a DHCT3, are established as follows:

MAXIMUM ALLOWABLE EMISSION LIMITS

POLLUTANT	FUEL	BACT STANDARD	LBS/HR *	TPY
NO_x	Gas	15 ppmvd @ 15% Oxygen	58	55
	Oil	42 ppmvd @ 15% Oxygen	184	184
PM_{10}	Gas	Good combustion; visible emissions shall not exceed 10% opacity	7 **	7 **
	Oil	Good combustion of low sulfur oil; visible emissions shall not exceed 10% opacity	15 **	15 **
SO_2	Gas	Good combustion	29 **	26 **
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	53 **	53 **
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		
H_2SO_4 Mist	Gas	Good combustion	3 **	3 **
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	6 **	6 **
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		

* These values are calculated using F-factors.
** Compliance shall be demonstrated through fuel sulfur analysis.

Monitoring

The BACT emission limitations for NO_x are one-hour averages. Compliance with these standards will be verified by a stack test and excess emissions will be monitored by a stack continuous emissions monitoring system (CEMS) for NO_x and oxygen. The NO_x CEMS will be

used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring which are required in 40 CFR 60, Subpart GG, and which are used as indicators of compliance with the NO_x standard specified in the subpart. Since the NO_x emission standard from Subpart GG is more than twice the BACT standard, monitoring for emissions in excess of the BACT limits using the NO_x CEMS is more stringent. FBN levels are not required for excess emission reports when excess emissions are reported based on the stack monitoring system. The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) will be replaced by certification tests of the NO_x CEMS.

<u>Details of the Analysis May be Obtained by Contacting</u>:

Martin Costello, BACT Coordinator, P.E.
Department of Environmental Protection
Bureau of Air Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Recommended by:	Approved by:
______________________	______________________
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Virginia B. Wetherell, Secretary Dept. of Environmental Protection
______________________, 1994 Date	______________________, 1994 Date

GAINESVILLE REGIONAL UTILITIES
<u>Conditions of Certification</u>
PA 74-04 and PSD-FL-212

AIR

The construction and operation of the Gainesville Regional Utilities (GRU) Deerhaven Combustion Turbine #3 (DHCT3) shall be in accordance with all applicable provisions of Chapters 62-210 through 297 and 62-4, Florida Administrative Code (F.A.C.), and 40 CFR 60, Subpart A, Subpart GG, Appendix A and Appendix B (1993 version). The following emission limitations and conditions reflect the BACT determinations for the DHCT3. In addition to the foregoing, the project shall comply with the following conditions of certification:

<u>General Operating Requirements</u>

1. The maximum heat input rates, based on high heating values of each fuel, to the DHCT3 and at ISO conditions (i.e., 59° F, 60% relative humidity and 101.3 kilopascals pressure), shall not exceed 971.1 MMBTU/hr, while firing natural gas, nor 990.6 MMBTU/hr, while firing fuel oil. Heat input will vary depending on ambient conditions and the DHCT3 characteristics. Manufacturer's curves or equations for correction to other ambient conditions shall be provided to the Department of Environmental Protection (DEP) at least 90 days before initial compliance testing.

2. The DHCT3 is allowed to operate up to 3900 hours per year, but not to exceed 2000 hours while firing fuel oil.

3. Only natural gas (NG) or No. 2 fuel oil shall be fired in the combustion turbine. The maximum sulfur content of the fuel oil shall not exceed 0.05 percent, by weight. GRU has established that there is approximately 55 hours of full load operation of fuel oil, which contains nominally 0.25% sulfur content, by weight, remaining in the fuel storage tank. GRU will be allowed to deplete this reserve by firing the fuel oil in the DHCT3. However, all future deliveries of fuel oil for the DHCT3 shall meet the BACT requirement, which limits the fuel oil sulfur content to no more than 0.05%, by weight. Fuel sulfur content shall be determined and recorded each time fuel is transferred into the bulk storage tank(s).

4. 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 pursuant to Rule 62-296.310(3), F.A.C. - Unconfined Emissions of Particulate Matter.

5. Any change in the method of operation, equipment or operating hours, pursuant to Rule 62-212.200, F.A.C., Definitions-Modifications, shall be submitted to the DEP's Bureau of Air Regulation office and Northeast District office.

Emission Limits

6. The maximum allowable emissions from the DHCT3, when firing natural gas or No. 2 fuel oil, in accordance with the BACT determination, and at 95 - 100% percent load based on the manufacturer's curves submitted to the DEP, shall not exceed the following limits except during periods of start up, shutdown, and malfunction pursuant to Rule 62-210.700, F.A.C.:

MAXIMUM ALLOWABLE EMISSION LIMITS

POLLUTANT	FUEL	BACT STANDARD	LBS/HR *	TPY
NO_x	Gas	15 ppmvd @ 15% Oxygen	58	55
	Oil	42 ppmvd @ 15% Oxygen	184	184
PM_{10}	Gas	Good combustion; visible emissions shall not exceed 10% opacity	7 **	7 **
	Oil	Good combustion of low sulfur oil; visible emissions shall not exceed 10% opacity	15 **	15 **
SO_2	Gas	Good combustion	29 **	28 **
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	53 **	53 **
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		
H_2SO_4 Mist	Gas	Good combustion	3 **	3 **
	Oil	Good combustion of low sulfur fuel oil: max. 0.05% sulfur content, by weight	6 **	6 **
	Oil	Good combustion, limited quantity: max. 0.25% sulfur content, by weight		

* These values are calculated using F-factors.
** Compliance shall be demonstrated through fuel sulfur analysis.

7. Visible emissions shall not exceed 10% opacity when firing natural gas or No. 2 fuel oil.

8. The potential emissions projected from the DHCT3 are:

ESTIMATED POTENTIAL EMISSIONS

Pollutant	Method of Control	TPY **
CO	Good combustion, proper use of water injection system	95.4
VOC	Good combustion	8.9
Inorganic Arsenic	Natural Gas/No. 2 Fuel Oil	0
Mercury	Natural Gas/No. 2 Fuel Oil	0.001
Pb	Natural Gas/No. 2 Fuel Oil	0.0638
Be	Natural Gas/No. 2 Fuel Oil	0.00033

** TPY values are for annual operation reports (AOR) and PSD applicability determinations. These values are based on the DHCT3 operating at full load at ISO for a total of 3900 hours per year, with up to 2000 hours of No. 2 fuel oil-fired operation.

Compliance Determination

9. Compliance with the allowable emission limiting standards shall be determined within 60 days after achieving the maximum production rate at which this unit will be operated, but not later than 180 days of initial operation at the maximum capability of the unit and annually thereafter, by using the following reference methods as described in 40 CFR 60, Appendix A (1993 version), and adopted by reference in Chapter 62-297, F.A.C.

Initial (I) compliance tests shall be performed on the DHCT3 while firing each fuel (gas, oil). Annual (A) compliance tests shall be performed during every federal fiscal year (October 1 - September 30) pursuant to Rule 62-297.340, F.A.C., on the DHCT3 with the fuel(s) used for more than 400 hours in the preceding 12-month period.

- Method 9 Visual Determination of the Opacity of Emissions from Stationary Sources (I,A)

- Method 10 Determination of Carbon Monoxide Emissions from Stationary Sources (I)

- Method 20 Determination of Nitrogen Oxides and Diluent Emissions from Stationary Gas Turbines (I,A)

Note: No other methods may be used for compliance testing unless prior DEP approval is received in writing. The DEP may request a special compliance test pursuant to Rule 62-297.340(2), 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.

10. Notwithstanding the requirements of Rule 62-297.340, F.A.C., the exclusive use of fuel oil with a maximum sulfur content limit of 0.05% or less, by weight, is the method for determining compliance for SO_2, H_2SO_4 mist, and PM_{10}. There is no suitable method for the testing of PM_{10} from this type of emissions unit, and the SO_2 and H_2SO_4 emissions are clearly limited by the sulfur content of the fuel. Compliance with the SO_2 and sulfuric acid mist emission limits shall be determined by fuel oil analysis using ASTM D2880-71 or D4294 (or equivalent) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or D3246-81 (or equivalent) for sulfur content of gaseous fuel. Alternatively, natural gas supplier data for sulfur content may be submitted. However, the applicant is responsible for ensuring that the procedures above are used for determination of fuel sulfur content. 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) (1993 version).

11. Pursuant to Rule 62-212.410, F.A.C., the permittee shall install a dry low-NO_x combustor on the DHCT3 for NO_x control when firing natural gas. Control of NO_x when firing No. 2 fuel oil shall be accomplished by water injection.

12. An initial test for CO, concurrent with each NO_x test, is required to confirm that annual potential emissions will not exceed 100 TPY. The NOx and initial CO test results shall be the average of three valid one-hour runs. The DEP's Northeast District office shall be notified, in writing, at least 30 days prior to the initial compliance tests and at least 15 days before annual compliance test(s). The combustion turbine shall operate between 95% and 100% of maximum capacity for the ambient conditions experienced during compliance test(s). The turbine manufacturer's

heat input rates (based on the high heating value of the fuel) vs. ambient temperature curve shall be included with the compliance test results. The fuel feed rates and the high heating value of the fuels shall be established during the initial and annual compliance tests. Compliance test results shall be submitted to the DEP's Northeast District office no later than 45 days after completion of the last test run.

13. Excess NO_X emissions from this turbine resulting from startup, shutdown, malfunction, fuel switching or load change, shall be acceptable providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the DEP's Bureau of Air Regulation or the Northeast District office for a longer duration. Best operating practices shall be documented in writing and a copy submitted to the DEP's Northeast District office along with the initial compliance test data. The document may be updated as needed with all updates submitted to the DEP's Northeast District office within thirty (30) days of implementation and shall include time limitations on excess emissions caused by turbine startup.

Notification, Reporting and Recordkeeping

14. Notification and recordkeeping shall be in accordance with 40 CFR 60.7 (1993 version). The following protocols shall be submitted to the DEP's Northeast District office for approval:

a. CEMS - If applicable, the Federal Acid Rain Program requirements of 40 CFR 75 shall apply when those requirements become effective in Florida.

b. Performance Test Protocol - At least 30 days prior to conducting the initial performance tests required by this permit, the permittee shall submit to the DEP's Northeast District office for their review and approval: a protocol outlining the procedures to be followed; the test methods; and, any differences between the reference methods and the test methods proposed to be used to verify compliance with the conditions of this permit.

c. All measurements, records, and other data required to be maintained by GRU shall be retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These data shall be made available to the DEP representatives.

Monitoring Requirements

15. The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from this source. One-hour periods when NO_X emissions (ppmvd @ 15% oxygen) are above the BACT standards (15/42 gas/oil) shall be reported as excess emissions following the

format of 40 CFR 60.7 (1993 version). The continuous emission monitor must comply with Rule 62-297.500, F.A.C.; 40 CFR 60, Appendix F, Quality Assurance Procedures (1993 version) (or other DEP approved QA plan); 40 CFR 60, Appendix B, Performance Specification 2 (1993 version); or, if applicable, 40 CFR 75, Appendix A and Appendix B. Periods of startup, shutdown, fuel switching, malfunction, and load change shall be monitored and recorded. The NO_x CEMS will be used in lieu of the water/fuel monitoring system and fuel bound nitrogen (FBN) monitoring, which are required in accordance with 40 CFR 60, Subpart GG (1993 version), and are used as indicators of compliance with the NO_x standard specified in the subpart. Since the NO_x emission standard from Subpart GG is more than twice the BACT standard, monitoring for emissions in excess of the BACT limits using the NO_x CEMS is more stringent. FBN levels are not required for excess emission reports when excess emissions are reported and based on the stack monitoring system. The calibration of the water/fuel monitoring device required in 40 CFR 60.335(c)(2) (1993 version) will be replaced by certification tests of the NO_x CEMS.

16. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation, or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions and shall be prohibited pursuant to Rule 62-210.700, F.A.C.

17. The sulfur content of the fuel oil being fired in the combustion turbine shall be determined in accordance with 40 CFR 60.334(b) (1993 version). Any request for a future custom monitoring schedule shall be made in writing and directed to the DEP's Bureau of Air Regulation office. Any custom schedule approved by the DEP pursuant to 40 CFR 60.334(b) (1993 version) will be recognized as enforceable provisions of the permit, provided that the holder of this permit demonstrates that the provisions of the schedule will be adequate to assure continuous compliance. The records of natural gas and No. 2 fuel oil usage shall be kept by the company for a five-year period for regulatory agency inspection purposes.

Rule Requirements

18. The emission unit shall be in compliance with all applicable provisions of Chapter 403, Florida Statutes, and Chapters 62-4, 210, 212, 275, 296 and 297, F.A.C.

19. The emission unit shall be in compliance with all applicable requirements of 40 CFR 60, Subpart A, Appendix A and Appendix B (1993 version), Subpart GG - Standards of Performance for

Stationary Gas Turbines (1993 version), and Rule 62-296.800(2)(a), F.A.C. The Subpart GG requirement to correct test data to ISO conditions applies. However, such correction is not used for compliance determinations with the BACT standard(s). All notifications and reports required by this specific condition shall be submitted to the DEP's Northeast District office.

20. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (Rule 62-210.300(1), F.A.C.).

21. The emission unit shall be in compliance with all applicable provisions of Rule 62-210.650, F.A.C.: Circumvention; Rule 62-210.700, F.A.C.: Excess Emissions; Rule 62-296.800, F.A.C.: Standards of Performance for New Stationary Sources (NSPS); Chapter 62-297, F.A.C.: Stationary Sources - Emissions Monitoring; and, Rule 62-4.130, F.A.C.: Plant Operation - Problems.

22. If construction does not commence within 18 months of issuance of this permit, the permittee shall obtain from the DEP's Bureau of Air Regulation a review and, if necessary, a modification of the BACT determination and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 52.21(r)(2) (1993 version)).

23. Quarterly excess emission reports, in accordance with 40 CFR 60.7 and 60.334 (1993 version), shall be submitted to the DEP's Northeast District office.

24. Pursuant to Rule 62-210.370(2), F.A.C., Annual Operating Reports, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur content of the fuel being fired, fuel usage, hours of operation, air emissions limits, etc. Annual operating reports shall be sent to the DEP's Northeast District office by March 1st of each calendar year.

25. Stack sampling facilities shall be installed in accordance with Rule 62-297.345, F.A.C.

Modifications

26. The permittee shall give written notification to the DEP when there is any modification to this facility/emission unit pursuant to Rule 62-212.200, F.A.C., Definitions - Modifications. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of the application/request, if necessary. Such notice shall include, but not be limited to: information describing the precise nature of the change; modification(s) to any emission control system; production capacity of the facility/emissions unit before and after the change; and, the anticipated completion date of the change.

GAINESVILLE REGIONAL UTILITIES
Strategic Planning

September 19, 1994

RECEIVED
SEP 21 1994
Bureau of Air Regulation

Mr. Clair Fancy, Bureau Chief
Florida Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities
Proposed Deerhaven Combustion Turbine No. 3
September 2, 1994 Meeting Summary/Supplemental BACT Analysis

Dear Mr. Fancy:

Gainesville Regional Utilities ("GRU") appreciated the opportunity to meet with you and your staff on September 2, 1994 to discuss the major issues related to the permitting of Deerhaven Combustion Turbine No. 3. Pursuant to our discussions, GRU's understanding of these issues, specifically the NOx emission limitations, compliance demonstrations, and the fuel-bound nitrogen ("FBN") allowance, is as follows:

I. NOx Emission Limitations

The permit shall contain NOx limits as described below:

a) Concentration limits (ppmvd) - Natural gas firing: 15 ppmvd; fuel oil firing: 54 ppmvd (pending a final decision on the attached Supplemental BACT analysis); daily 24-hour block averages (midnight-midnight) @ 15% O_2, on a dry basis.

b) Mass emission limit (#/hr) - Natural gas firing: 58 lbs/hr; fuel oil firing: 237 lbs/hr (pending a final decision on the attached Supplemental BACT analysis); daily 24-hour block averages (midnight-midnight). These are the emission rates under the worst case operating conditions (i.e., 100% load, 20°F) as indicated in Attachment A to the Prevention of Significant Deterioration ("PSD") permit application.

c) Scaled adjustment for FBN - Due to the compliance method, the Department indicated a preference for a single NOx concentration limit rather than a scaled limit to account for FBN.

ISO correction of NOx concentrations will not be required except as necessary to demonstrate compliance with the 40 CFR 60 Subpart GG New Source Performance Standards.

(904) 334-3400 ext. 1261 P.O. Box 147117, Station A136, Gainesville, Florida 32614-7117 Fax: (904) 334-3151

demonstrate compliance with the 40 CFR 60 Subpart GG New Source Performance Standards.

II. NOx Compliance Methods

Compliance with the NOx emission limitations as described in I.a) and I.b) above shall be determined as follows:

a) Concentration limits (ppmvd) - Continuous emission monitoring system ("CEMS").

b) Mass Emission Limit (lbs/hr) - Periodic compliance test or CEMS. Based upon further evaluation, GRU's preference would be through a NOx CEMS and F-factor calculations (EPA Method 19). Please note that a volumetric flow monitor is not proposed for this unit.

III. Fuel-Bound Nitrogen

GRU agreed to submit a Supplemental BACT analysis (included herein as Attachment 1) for fuel-bound nitrogen. This analysis demonstrates that using a fuel specification to control NOx emissions is not cost effective. Therefore, GRU is requesting a NOx permit limit of 54 ppmvd and 237 lbs/hr when firing fuel oil. As demonstrated in the PSD permit application, this level of emissions would not have adverse effects on air quality.

GRU trusts this is an accurate summary of the meeting discussions. I will contact your staff next week to discuss the Supplemental BACT analysis and the proposed permit conditions. In the interim, if the Department has any questions or disagrees with the discussion summary, please call me at (904) 334-3400 Ext. 1284.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

xc: D. Beck
J. Braswell, FDEP
P. Cunningham, HBGS
D. Fulle, Enserch Environmental
T. Herron, FDEP
S. Manasco
B. Mitchell, FDEP

SUPPLEMENTAL BACT ANALYSIS FOR
FUEL BOUND NITROGEN
PROPOSED DEERHAVEN COMBUSTION TURBINE No.3
Gainesville Regional Utilities
September 19, 1994

INTRODUCTION

Gainesville Regional Utilities ("GRU") is proposing to install a General Electric ("GE") MS70001EA simple cycle combustion turbine, equipped with recently developed, dry low NOx ("DLN") combustors. The unit is expected to be permitted to operate, while burning the unit's primary fuel, which is natural gas, with a continuous NOx emission rate of no more than 15 ppmvd @ 15% O2. Planned to become operational in mid 1995, this will be the first unit in Florida operating with a permit limit of less than 25 ppmvd @15% O2.

While burning distillate fuel oil, which is the unit's secondary or backup fuel, NOx control will be achieved using a more conventional water injection technology. Water injection in a simple cycle combustion turbine acts to control thermally generated NOx, but nitrogen bound in the fuel is directly converted to NOx through the combustion process. At higher levels of fuel bound nitrogen ("FBN"), emissions will be correspondingly higher. Accordingly, GRU is requesting a fuel-bound nitrogen allowance for fuel oil burned up to .03%.

PURPOSE AND SCOPE

The Florida Department of Environmental Protection has requested GRU to demonstrate that setting a continuous (24 hour block average) emission limit of 42 ppmvd @15% O_2, while operating on fuel oil, would impose costs upon GRU that would not be feasible according to EPA's Best Available Control Technology ("BACT") guidelines.

There are several approaches for controlling NOx to a limit of 42 ppmvd NOx @15% O_2 while burning oil in a DLN combustor turbine including:

1. Over controlling with water; and
2. Burning oil with less than .015% FBN.

The technical feasibility of over-controlling with water was determined by GE, the manufacturer of the turbine. The implications of being required to burn oil with less than .015% FBN on fuel price and availability were assessed by a survey of fuel suppliers in Florida.

OVER-CONTROLLING WITH WATER

One way to compensate for FBN is to further reduce thermal NOx by injecting additional water. For example, to reduce NOx from 54 to 48 ppmvd @15%O2 would require reducing thermal NOx by 6 ppmvd with the following consequences (see Attachment 1 - July 27 letter from General Electric):

1. Increased high-quality water consumption (5,000-6,000 lb/hr);
2. Adverse effects on equipment life and additional maintenance cycles;
3. Higher carbon monoxide ("CO") and uncontrolled hydrocarbon ("UHC") emissions;
4. Decreased unit efficiency (40-60 BTU/KWH).

These conditions would be even more exacerbated if water is injected to control to the 42 ppmvd level, if it is even technically possible. Therefore, given the environmental consequences and potential for damage to the unit, over-control with water is not considered feasible nor prudent.

LOW FBN FUEL ANALYSIS

A survey was conducted to assess the availability and cost of No. 2 low sulfur fuel oil with a maximum FBN of .015%. A fuel solicitation was prepared, containing fuel specifications (e.g. less than .05% sulfur) and requesting quotes <u>with</u> a guaranteed FBN less than or equal to .015% and <u>without</u> a guaranteed FBN content (Attachment 2). This threshold was selected because GE has represented that a 42 ppmvd @15% O2 limit can be achieved with FBN up to .015%. The request for quotation was submitted to nine fuel suppliers. Five quotations were obtained with only one supplying a FBN guarantee. The results are summarized in Table 1 (Attachments 3 through 9).

TABLE 1
NO. 2 LOW SULFUR FUEL OIL
QUOTE SUMMARY
($/gallon F.O.B Gainesville, Fl.)

Vendor	Without Fuel-Bound Nitrogen Guarantee	With Fuel-Bound Nitrogen $\leq$.015% Guarantee	Difference
Steuart	.5905	No Bid	na
Central Oil	.5982	No Bid	na
Coastal	.6087	.6304	.0217
BP Oil	.5836	No Bid	na
MGRefining	No Bid	No Bid	na
average	.5952	.6304	.0352

The only supplier willing to guarantee the FBN quality of its oil charged a .0217 $/gallon premium (3.6%).

During the survey process it became apparent that the market for oil with low FBN content is currently not well developed in Florida, and that in most cases, FBN is not a factor in fuel oil purchasing decisions. BP Oil (British Petroleum) was known to supply oil for units requiring low FBN oil to meet permit requirements, so BP personnel were contacted for a more in depth discussion when BP failed to offer a price for guaranteed low FBN fuel oil. BP indicated that to serve the units in question, each batch of oil is tested prior to delivery. The FBN quanity in the oil is not under the control of the supplier, and its availability depends upon the original source of the crude oil.

Given the overall lack of FBN sampling in the fuel oil market, it is difficult to determine the reduction in FBN that would be attained by requiring a maximum FBN content of .015%. Accordingly, the cost per ton (see attachment 10-NOx Reduction Calculations) using the difference of the bid prices from Coastal (minimum differential) as well as the difference between the average of the non-guarantee prices and the Coastal guarantee price (average differential), is shown below:

Table 2
NOx Control Costs Using Fuel Specification
($/ton NOx)

Minimum differential	$12,136
Average differential	$19,687

These costs are greater than would be considered cost-effective pursuant to EPA BACT guidelines. In addition, these costs do not reflect any infrastructural changes to the on-site fuel storage and handling facilities which may be required.

SUMMARY AND DISCUSSION

Given the environmental consequences and potential for damage to the unit from over-control with water, this alternative for compensating for FBN concentration greater than .015% is not considered feasible nor prudent.

The results of the survey indicate that the market for low FBN No. 2 fuel oil is not yet fully developed, since over 80% of the suppliers responding to GRU's solicitation have both not adopted a fee structure reflecting FBN and are not willing to guarantee the FBN content of their supply at this time. Furthermore, the availability of the lower FBN fuel is not assured at any given point in time.

A single data point was found indicating the premium that the market will currently bear for low FBN fuel oil is $.0217/gallon, or about 3.6%. At this premium the cost per ton of NOx reduction is not cost effective.

REFERENCE

1. Enserch Environmental Corporation, Prevention of Significant Deterioration Permit Application for Gainesville Regional Utilities Deerhaven Generation Station Combustion Turbine Addition. February 1994

ATTACHMENT 1

GE Power Generation Engineering

Project Engineering
General Electric Company, Bldg. 2, Suite 430
One River Road, Schenectady, NY 12345 USA
Phone: (518) 385-9219 Dial Comm: 8*235-9219
FAX: (518) 385-5128 FAX Dial Comm: 8*235-5128

Date: July 27, 1994

Copies:

R Beaudoin	53-322	MM Schorr	2-647
W Cantillion	GVL 236	R Gordon	23-113
J Chalfin	22-237	R Pavri	37-2C
M Cardano	Tampa	LB/File	

Subject: **Gainesville Regional Utilities**
GR0292 - Deerhaven Combustion Turbine #3

To: Doug Beck / Yolanta E Jonynas
Gainesville Regional Utilities
301 SE 4th Avenue
Gainesville, FL 32601

This letter summarizes the GE position on organic NO_x yield for combustors burning fuels containing elevated levels (above 0.015% by weight) fuel bound nitrogen (FBN). The term organic NO_x is used to differentiate between NO_x derived from organic FBN and thermal NO_x derived from the reaction atmospheric nitrogen at elevated temperatures and pressure within combustors. The conversion rate of FBN to organic NO_x is a function of combustor design, operating conditions and FBN content. Regarding the subject fuel, which has been conservatively estimated to contain 0.03% by weight FBN, previous studies (with FBN levels ranging from 0.01%-1.0%+ by weight) on GE conventional diffusion flame gas turbine combustors have shown nearly a 100% conversion of FBN to exhaust NO_x. .

At any given level of fuel bound nitrogen, Dry Low NO_x (DLN) lean pre-mixed combustors are expected to have a higher NO_x yield than conventional diffusion flame combustors. The air flow distribution within DLN lean pre-mixed combustors, even when operating in diffusion mode on liquid (distillate) fuel, is such that the flame zone is much leaner than in conventional diffusion flame combustors. Both GE studies and available literature (see References 1 and 2) indicate leaner flames will have increased NO_x yields and resultant higher exhaust NO_x levels. Diluent injection technology (water or steam injection) is effective in controlling thermal NO_x, but has no effect in reducing organic NO_x. Actually water or steam injection in conventional diffusion flames increases the conversion of organic FBN to exhaust NO_x. In light of the above, plus the fact that we have no DLN combustor data (either laboratory or field), upon which to base a guarantee GE cannot commit to guarantees at less than 100% yield. There would not be any recourse if such a guarantee were made and subsequently could not be met.

Based on the above, GE's position is that the Gainesville permit for Deerhaven Combustion Turbine #3 should be based on NO_x emissions levels reported in our proposal (54 ppmvd NOx @ 15% O2), when burning distillate fuel containing 0.03% (by weight) nitrogen in the fuel. Note that total NO_x of 54 ppmvd is calculated by assuming 42 ppmvd thermal NOx contribution and 12 ppmvd organic NOx from fuel bound nitrogen based on 100% yield at the 0.03% level by weight. The 12 ppmvd NO_x allowance is in accordance with the guidelines in 40CFR60 subpart GG.

A reduction in total exhaust NO_x level (say from 54 ppmvd to 48 ppmvd @ 15% O_2) would mean that the Deerhaven unit would have to operate at a thermal NO_x level of 36 ppmvd @ 15% O_2 instead of 42 ppmvd, since organic NO_x is not reduced by water injection. Should Gainesville Regional Utilities be required to operate the Deerhaven Combustion Unit #3 at the lower total NO_x level (I.E. 48 ppmvd NO_x) exhaust this would raise a number of serious issues which are of concern and these are as follows: First, there is a significant increase in water usage (on the order of 15-20% which corresponds to about 5,000-6,000 lb/h) water flow. There is both an economic and resource issue (since high quality water is itself a scarce resource) with increased use of treated water. Second, the higher water injection rates will cause increased combustion dynamics and thermal stresses, thereby negatively impacting hardware life resulting additional maintenance. Third, the addition of excessive amounts of water in the combustor, especially at part loads will result in higher CO and UHC emissions. Very high rates of water injection act to quench the flame and interferes with the burning process resulting in additional concentrations of non-complete products of combustion (I.E. CO and UHC). Fourth, the overall machine efficiency is decreased by the additional amount of water injection. Heat rate (measured in Btu/kWh) is increased (thereby decreasing unit thermal efficiency) on the order of 40-60 Btu/kWh when water levels are increased by the magnitude noted above. This additional heat rate penalty will directly translate into an economic penalty to the turbine owners, since fuel usage will be increased.

While it is not GE's position to dictate machine permit levels, as a responsible manufacturer we feel it is only fair to inform our customers and appropriate regulatory agencies of the consequences of operating our equipment under various conditions. Hopefully by presenting this information both Gainesville Regional Utilities and the regulatory authorities can make an informed, intelligent decision on the appropriate emissions level for this project.

Michael A. Davi

Michael A. Davi, Senior Program Manager
GT Applications Engineering
md/

References:

1. Gerhold, BW, et. al., "Two Stage Combustion of Plain and N-Doped Oil", 17th Symposium (International) on Combustion, The Combustion Institute, 1979.

2. Wilkes, Colin and Russell, RC, "The Effects of Fuel-Bound Nitrogen Concentration and Water Injection on NOx Emissions from a 75 MW Gas Turbine", ASME 78-GT-89, 1978.

GRU

Request for Price Quotations
No. 2 Diesel Fuel

Gainesville Regional Utilities (GRU) is requesting price quotations for No. 2 Diesel fuel for its power plants based on the specifications listed below. Please fax your quote to Karen Alford, Utility Analyst, (904)334-2818 (or 334-2786) by September 8, 1994, 4:00 p.m. If you are unable to submit a quotation and would like to remain on GRU's bid list, please notify GRU via fax by the deadline stated. For additional information, please contact Karen Alford at (904)334-3400, ext.1730.

Quantity:	Approximately 100,000 gallons	
Delivery Location:	Gainesville, Florida (Deerhaven, Hague FL)	
Unloading Facilities:	24 hours/day, 7 days/week (Must provide unloading pump.)	
Specifications:	BTU/gal	137,000 min.
	Sulfur by weight	**0.05% max.**
	Bottom Sediment/water	0.1% max.
	Ash by weight	0.05% max.
	Viscosity (100°F)	1.8-4.8 Centistrokes
	Vanadium	200 PPM
	Fuel Bound Nitrogen[1]	**0.015% max. [1]**

[1] Please submit two price quotes:
Quote A - Include guaranteed Fuel Bound Nitrogen less than .015%
Quote B - No specified or guaranteed Fuel Bound Nitrogen content.

Terms and Conditions:	Price quotations should include all applicable taxes. Prices to be quoted F.O.B. Gainesville, Florida Please include payment terms.
Submission Deadline:	Thursday, September 8, 1994 , 4:00 p.m. EST

METALLGESELLSCHAFT CORP.

520 Madison Avenue
New York, N.Y. 10022
Telephone: (212) 715-5200

September 8,1994

GAINESVILLE REG. UTILITIES
ATTENTION: KAREN ALFORD
FAX:904-334-2818

RE: NO BID FOR FUEL

Dear Administrator:

Thank you for considering MG REFINING & MARKETING, INC. for the above referenced solicitation. However, we will not be bidding on these requirements at this time.

Again, thank you for the opportunity. Please keep us on your bidders list for future solicitations for heating fuels and transportations fuels.

Sincerely,

Dawn Kretchmer

Dawn Kretchmer
MG Refining & Marketing

/FAX +

BP Oil Company
9040 Roswell Rd, Suite 520
Atlanta, GA 30350-1199

Phone: 1-800-544-3210 / Fax: 404 641-2559

ATTN: MS KAREN ALFORD
GAINESVILLE REGIONAL UTIL
P O BOX 490
GAINESVILLE FL 32602

09/08/94

DEAR KAREN,

The following fuel prices were in effect at your location(s) noted below, effective 11:50 AM on 09/08/94.

DELIVERY LOCATION	CUSTOMER NUMBER	TERM	PROD	FOB PRICE	FREIGHT	DELIV PRICE	FEES/ TAXES	TOTAL PRICE
GAINESVILLE	24446254	JACKSO	DL2	53.000	2.940	55.940	2.421	58.361

* DL2 = Low Sulfur, On Road Use / FO2 or DS2 = Off Road Use, High Sulfur

Market fluctuations can create an opportunity to make pricing adjustments during the course of the day. To receive market updates and your most current pricing information, or to place fuel orders please give me a call on our BP GOLDLINE... 1-800-544-3210 (option 1-6).

Your current payment terms are NET 30 DAYS/DATE OF DELV.

I appreciate the opportunity to serve your fuel purchasing needs.

SINCERELY,

ED GALLO
ACCOUNT EXECUTIVE

Fees\ Taxes

2.071 Environmental

0.350 SuperFund

2.421 Total

BP OIL

BP Oil Company
9040 Roswell Road, Suite 520
Atlanta, Georgia 30350 - 1199
1-800-544-3210
(404) 641-2500

Date: 9\8\94

Time: 1:00

Sent To: Karen Alford At: Gainesville Regional

Fax Number: 904 334 2818
(or) 2786

Sent From: Ed A. Gallo
Account Executive

At: BP Oil Company
Atlanta, GA

Messages: Karen,
Here is our current price for low sulfur diesel fuel delivered to your Deerhaven location. An analysis will be ran at time of delivery to determine the nitrogen level. Please give me a call if you have any questions

Thanks

Ed

To Reply by Phone: (404) 641-2516 BP Goldline: (800) 544-3210, *Option 6*

To Reply by Fax: (404) 641-2559

BP OIL

BP Oil Company
9040 Roswell Road, Suite 520
Atlanta, Georgia 30350 - 1199
1-800-544-3210
(404) 641-2500

Date: 9\9\94

Time: 12:00

Sent To: Karen Alford At: Gainesville Regional

Fax Number: 904 334 2818
(or) 2786

Sent From: Ed A. Gallo At: BP Oil Company
Account Executive Atlanta, GA

Messages: Karen,
To further clarify, our procedure will be to verify the nitrogen level at the time of potential delivery & we will provide you with a copy of this analysis. We are the main supplier for Walt Disney World (i.e. Reedy Creek) who also requires a similar procedure & specification for nitrogen, & we look forward to providing your organization with the same service.

To Reply by Phone: (404) 641-2516 BP Goldline: (800) 544-3210, *Option 6*

To Reply by Fax: (404) 641-2559

eap/faxform.123

Central Oil Co., Inc.

1001 McCloskey Blvd. Tampa, FL 33605 (813)248-2105 FAX (813)247-3567

Facsimile Cover Sheet

To:	Karen Alford
Company:	Gainesvill Regional Utilities
Phone:	(904) 334-3400, ext. 1730
Fax	(904) 334-2818.
From:	Dale A. Roberts
Company:	Central Oil Co., Inc.
Phone:	(813)248-2105
Fax:	(813)247-3567
Date:	September 8, 1994
Pages including this cover page:	1

Quote "B"

Comments: Our Current Price for .05% max Sulfur #2 Fuel Oil is $0.5982 Per gallon F.O.B. your Storage. This includes Product, State + Federal Pollution Taxes and Freight.

This Price firm thru business hours of September 9, 1994.

Dale A. Roberts

STEUART Petroleum Company

P.O. Box 26306
Jacksonville, Florida
32226-6306
6531 Evergreen Avenue
Jacksonville, Florida
32208
(904) 355-9675
(800) 842-3624
Fax (904) 354-2811

September 8, 1994

Karen Alford
Utility Analyst
Gainesville Regional Utilities

Fax Number: 904-334-~~3400~~ 2818

Thank you for the opportunity to bid to supply approximately 100,000 gallons of No. 2 diesel fuel. Our bid is as follows:

Quote A:	No Bid
Quote B:	.5905 delivered
Payment Terms:	10 days from date of delivery

Please let us know how we may be of service to Gainesville Regional Utilities.

Sincerely,

Robert A. Bosman
Marketing Representative

RAB/hc

Coastal
The Energy People

TO: Karen Alford, Utility Analyst
Gainesville Regional Utilities

FAX NO.: 904-334-2818/2786

DATE: September 8, 1994

SUBJECT: GRU'S REQUEST FOR PRICE QUOTATIONS - NO. 2 DIESEL FUEL

FROM: J. R. Sauls, Director Utility Sales

Quantity: Approximately 100,000 Gallons

Delivery Location: Gainesville, Florida

Quote A Guaranteed Nitrogen	Quote B No Guaranteed Nitrogen
$0.630413/Gallon Delivered	$0.608713/Gallon Delivered

Delivery Window: September 12 - 16, 1994

Payment Terms: Net 30 Days Date of Invoice

Coastal Refining & Marketing, Inc.
A SUBSIDIARY OF THE COASTAL CORPORATION
P O BOX 025500 • MIAMI FL 33102-5500 • 305/551-5300

ATTACHMENT 10

NOx Reduction Calculations
Fuel Oil Firing

Conditions: 100% load, ISO, fuel flow=50,380 lbs/hr. Calculations assume 100% conversion of FBN to NOx as NO2.

1. Fuel Cost Differential

Minimum = \$0.0217/gal
Average = \$0.0352/gal

2. FBN Reduction

0.03% - 0.015% = 0.015%

3. NOx Reduction Associated with FBN Reduction

lbs/hr = (.015/100) (50,380 lbs/hr) (46 lbs NO2/14 lbs N) = 24.83 lbs/hr

tons/yr = (24.83 lbs/hr) (2000 hrs/yr) (1/2000 lbs/ton) = 24.83 tons/yr

4. NOx Reduction Cost (\$/ton)

a.) Minimum Fuel Cost Differential

= (50,380 lbs/hr) (1/7.2558 lbs/gal) (2000 hrs/yr) (\$0.0217/gal)

= \$301,344

\$/ton NOx = \$301,344/24.83 = \$12,136/ton

b.) Average Fuel Cost Differential

= (50,380 lbs/hr) (1/7.2558 lbs/gal) (2000 hrs/yr) (\$0.0352 /gal)

= \$488,816

\$/ton NOx = \$488,816/24.83 = \$19,867/ton

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning

RECEIVED

AUG 12 1994

Bureau of
Air Regulation

VIA OVERNIGHT MAIL

August 11, 1994

Ms. Teresa Herron
Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: Gainesville Regional Utilities
Proposed Deerhaven Combustion Turbine No. 3
Draft BACT Determination and Conditions of Certification (PA 74-04)

Dear Ms. Herron:

This letter provides Gainesville Regional Utilities' ("GRU") initial comments on the draft Best Available Control Technology ("BACT") Determination and Conditions of Certification for the proposed Deerhaven Combustion Turbine No. 3 ("DHCT3").

Specific comments are provided on Attachments 1 and 2 and the marked-up copies of the above referenced documents. GRU's major concerns are discussed below and focus primarily on the following issues: a) ISO-correction requirements for NO_x emission limits and b) Fuel-bound ("FBN") nitrogen allowances.

<u>ISO-CORRECTION REQUIREMENTS FOR NO_x EMISSION LIMITS</u>

The Department is proposing a NO_x emission limit based on ISO-corrected measured NO_x emissions for DHCT3 beginning January 1, 1998. GRU questions the Department's rationale for imposing this requirement both from a regulatory and technical perspective.

REGULATORY ISSUES

1) <u>NSPS vs. BACT Requirements</u>

GRU's concerns over the Department's proposed permit condition to correct the BACT-based NO_x emission limit to ISO conditions is founded on the basis of its BACT determination.

As the Department is aware the New Source Performance Standards ("NSPS") for combustion turbines require compliance with the NSPS limit for NO_x to be demonstrated at ISO conditions (40 CFR 60 Subpart GG). The demonstration is based on the ambient conditions during testing and the appropriate equations set forth in 40 CFR 60.335. The NSPS limit for NO_x was established in September of 1979 and represented a "national standard". Development of this "national standard" included input from the various combustion turbine manufacturers. These manufacturers were aware throughout the development, proposal and eventual promulgation of the NSPS that they would be required to develop combustion turbines which could meet the NSPS limit when corrected to ISO conditions.

The BACT process, however, involves case-by-case determinations based on available and demonstrated technologies, environmental considerations and economics. In most cases current BACT determinations, which have been reported nationally through the U.S. Environmental Protection Agency's ("EPA") BACT/LAER Clearinghouse, are not requiring ISO-corrections. GRU's BACT evaluation, which followed standard EPA procedures and guidance, resulted in proposed BACT emission limits for this project of 15 and 54 ppmvd, corrected to 15% oxygen, when firing natural gas and fuel oil, respectively. GRU's assumption that the Department would establish emission limits based on non ISO-corrected conditions was based on past BACT determinations and the recent EPA Alternative Control Techniques Document - NO_x Emissions from Stationary Gas Turbines, both of which do not specify ISO-correction. Under this assumption GRU approached the various combustion turbine manufacturers and requested availability of and associated guarantees for combustion turbines capable of meeting these emission limitations and GRU's power demands. GRU's request did not address correction of the exhaust gas concentrations for the proposed emission limits to ISO conditions since the basis of the emission limitations (i.e., BACT/LAER Clearinghouse) were not ISO-corrected. Consequently, General Electric ("GE") is unable to provide guarantees for ISO-corrected NO_x emissions.

Because GRU's has based its proposed BACT emission limits on non ISO conditions, it is appropriate for the Department to issue BACT limits based on these same conditions. The Department's intent to change the basis for computing BACT emission limits, while holding the exhaust gas concentrations at the requested levels, represents questionable engineering judgment.

2) Reduction of BACT-based limits

The effects of ISO-correction on BACT-determined emission levels can become significant. Figure 1 illustrates the observed NO_x levels required to meet the Department's proposed limit of 15 ppmvd after ISO-corrections are applied. As illustrated, ISO-correction would require actual emissions to be approximately 20% lower (i.e., less than 12 ppmvd) than GRU's BACT-determined level (i.e., 15 ppmvd not ISO-corrected). These lower levels are inconsistent with GRU's BACT analysis. This analysis, which considered technical, economical and environmental issues, identified dry low-NO_x ("DLN") combustors and water injection as the commercially available and "demonstrated" technology capable of controlling nitrogen oxide emissions from the proposed combustion turbine. Emission levels associated with these technologies are 15 ppmvd and 42 ppmvd (plus fuel-bound nitrogen allowance) when firing natural gas and fuel oil, respectively, and without applying ISO-corrections. From another perspective, Figure 2 is a representation of how the ISO-corrected concentrations would vary while holding exhaust gas concentrations at GRU's proposed BACT limit of 15 ppmvd (not ISO-corrected). Therefore, if the Department imposes ISO-corrected limits, GRU requests the opportunity to adjust its proposed emission levels for this project accordingly.

A BACT analysis, by its terms, should consider those technologies that are available and have demonstrated the ability to control a particular emission. A BACT determination is established as of the date the permit is issued, based upon those control technologies available in the marketplace or demonstrated by operating experience as capable at that time of achieving the identified BACT emission limits. A BACT analysis is not intended to anticipate control technologies which are not yet commercially demonstrated or which may become available after the permit is issued or after the permitted source becomes operational. To consider unavailable or undemonstrated technologies or emission limits is too speculative and imprecise as to costs and technical feasibility to perform a reliable BACT analysis. At this time, GRU is not aware of any demonstrated or operational dry low NO_x/wet injection control systems now capable or projected to be capable in June 1995 (GRU's in-service date) of continuously achieving NO_x levels less than GRU's proposed non ISO-corrected emission rates of 15 ppmvd and 42 ppmvd, respectively.

Furthermore, GRU has no basis for believing that the proposed combustion turbine will be able to achieve a lower NO_x emission rate in January 1998, merely due to the passage of time. GE has not provided and is unable to provide GRU with any evidence (i.e., commercial performance guarantees) that this combustion turbine will be able to meet a NO_x emission limit less than 15 ppmvd at 15% O_2. The economic costs and other impacts associated with any required modifications of the combustion turbine and combustors to meet a lower limit in the future have not been estimated nor addressed as part of the BACT analysis. GRU is aware of no information which would support setting the NO_x limit at an ISO-corrected level beginning in January 1998. Simple marketing representations of manufacturers' goals for future control technologies and emission limits are not an adequate legal basis for setting BACT limits.

GRU's proposed BACT NO_x emission limits of 15 ppmvd and 42 ppmvd (not ISO-corrected) during natural gas and fuel oil firing, respectively, are consistent with other recent DEP-issued PSD permits for similar gas-fired combustion turbine projects, both in combined cycle and simple cycle applications. These recent permits are for projects with in-service dates of 1994 and 1995, but with the 15 ppmvd limit not applicable until late 1997 or early 1998; until those dates, NO_x emission limits have been typically set at 25 ppmvd non ISO-corrected.

However, GRU is proposing a 15 ppmvd NO_x limit for its combustion turbine as of June 1995, approximately 2.5 years earlier than other units are being required to achieve that emission limit. Thus, for projects with contemporary operational dates, GRU already is proposing NO_x limits for its combustion turbine below those set by DEP for other projects.

TECHNICAL ISSUES

Further adjustments to the NO_x limits resulting from ISO-correction requirements would result in NO_x levels that are not technically achievable by the DLN combustors on a continuous basis. According to GE, these combustors have been designed and developed to produce a fixed exhaust NO_x concentration of 15 ppmvd over a wide range of ambient conditions without regard to ISO-corrections. Application of ISO-corrections to the design NO_x emission levels would result in adjusted NO_x emission limits beyond DLN combustor capability. GRU cannot accept a limit that the manufacturer cannot achieve or guarantee. Furthermore, issuance by the Department of a permit with limits that GRU cannot meet violates the provisions of Chapters 17-4.030 and 17-4.070 F.A.C.

NO_x emissions while firing distillate fuel oil will be controlled by water injection. Technically, it is possible to inject additional water to reduce NO_x emissions below BACT-based limits but, as described in correspondence from General Electric ("GE") dated July 27, 1994 (Attachment 3), there are significant penalties associated with over-injection of water, including efficiency loss, increased water consumption, increased emissions of hydrocarbons and volatile organic compounds, and negative impacts on machine operability and durability. These penalties are not warranted based on the BACT analysis.

FUEL-BOUND NITROGEN ("FBN") ALLOWANCE

The Department has proposed a FBN allowance of up to 6 ppmvd for distillate fuel, conservatively estimated to contain a maximum FBN level of 0.03% by weight. This allowance is not consistent with 40 CFR 60 Subpart GG which would allow up to an additional 12 ppmvd for this same fuel, calculated as follows:

Fuel-Bound Nitrogen (% by weight)	F (NO_x % by volume)
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)

As described in their letter dated July 27, 1994 (Attachment 3), General Electric has relied on this formula and their knowledge of FBN-to-NO_x conversion rates to calculate the 54 ppmvd emission rate guaranteed for DHCT3 during fuel oil combustion. GE's position is consistent with Standards Support and Environmental Impact Statement. Volume 1: Proposed Standards of Performance for Stationary Gas Turbines, PB-272 422, EPA, September 1977 (prepared during the promulgation of 40 CFR Subpart GG) which states that "below a fuel-bound nitrogen level of about 0.05 percent, essentially 100 percent (of organic nitrogen) is converted to NO_x" (see attached Figure 8-4). The Department's FBN formula appears to assume that because the NSPS formula indicates a zero NO_x allowance for fuel with a nitrogen content of 0.015% or less, that there is no FBN present. This is not consistent with EPA's studies which acknowledged that nitrogen is present but not quantifiable at that level. The Subpart GG formula recognizes this and therefore does not subtract out, like the Department does in their calculation, the contribution from the initial 0.015% FBN for fuels with FBN greater than 0.015%.

The BACT analyses for NO_x considers those emissions that can be controlled (e.g., thermal and prompt NO_x). It is GRU's understanding that at this time organic NO_x derived from FBN cannot be controlled other than by burning lower nitrogen-containing fuel. GRU's findings, and the Department's recognition, has been that nitrogen is not a fuel specification. As detailed in GRU's April 20, 1994 correspondence with the Department, few fuel vendors analyze for nitrogen content and could not provide a typical analysis. GRU has recently contacted its fuel vendors again to obtain more current data on nitrogen content in low-sulfur fuel oils. The vendors again indicated that they do not routinely test for nitrogen and had very limited information to provide. Colonial Pipeline indicated that the nitrogen content varies widely and based on their available data is approximately 0.02%. Therefore, in the absence of a reasonable FBN allowance per the Subpart GG formula, the only alternative to control organic NO_x is to overcontrol the BACT-based thermal NO_x levels to comply with the Department's proposed limits. As indicated in GE's July 27, 1994 letter (Attachment 3), controlling NO_x to these levels (i.e., 36 ppmvd) will require additional water injection that will increase the wear and tear on the machine, reduce efficiency and increase HC and VOC emissions by altering the combustion characteristics. If ISO-correction is required actual emissions will have to be even lower. It should be noted that there is a practical limit to the amount of water than can be injected before the combustor flame stability is impaired or the flame is extinguished altogether. Furthermore, injection of water beyond a recommended limit adversely impacts GE's guarantee on the machine.

CONCLUSION

GRU believes it is inappropriate for the Department to require the NSPS derived ISO-correction factor in developing the proposed BACT emission limits and inequitable to unduly limit the NSPS FBN allowance in the manner proposed. If these corrections and factors are to be applied in establishing these BACT limits, the Department is being selective in applying only portions of the NSPS formulas and is unfairly penalizing the DHCT3 project. Specifically, the NSPS allows consideration of combustion turbine efficiency in setting the applicable NSPS limit for NO_x that a unit must meet. The Department's approach fails to make an allowance for such an efficiency factor. All of the NSPS factors should be applied if the Department elects to take such an approach in establishing BACT limits.

Therefore, GRU does not believe the Department's position is reasonable or supportable based upon the available information and requests that:

1) The Department issue BACT limits on a not ISO-corrected basis.

2) ISO-correction of NO_x emissions be applied only during the initial performance tests to demonstrate compliance with the NSPS NO_x emission limit. (In the event the Department requires ISO-correction on a continuous basis, GRU requests that the Department's limit be based on correction of GRU's requested BACT limit to ISO condition using the appropriate equation.)

3) NO_x emissions when burning fuel oil be permitted at 54 ppmvd by providing for the full FBN allowance pursuant to 40 CFR 60 Subpart GG for fuels up to 0.03% nitrogen.

GRU appreciates the opportunity to comment on the draft permit and believes it would be beneficial to further discuss these issues with the Department. I will contact you next week to arrange a meeting at the earliest Department's convenience.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Electric Utility Environmental Engineer

xc: C. Fancy, FDEP
F. Hancock
R. Casserleigh
D. Beck
D. Fulle
D. Roberts
DHGT3

ATTACHMENT 1

GRU COMMENTS
Best Available Control Technology Demonstration

1) Title - Page 1

Requested Change: Change "Authority" to "Utilities."

Rationale: Name correction.

2) Size of Unit - Page 1, paragraph 1

Requested Change: Specify that the 74 MW is "nominal."

Rationale: Unit output varies under different operating conditions.

3) Requested Operation - Page 1, paragraph 2

Requested Change: Reword as indicated below.

"The applicant has requested to ~~burn natural gas for 1510~~ operate the unit for 3900 hours per year, of which 390 hours may be in the power augmentation mode (PA) and up to a maximum of 2000 hours per year may be while firing distillate fuel oil, with a 0.05 percent sulfur content ~~for a maximum of 2000 hours per year~~. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the ~~facility~~ combustion turbine at 100 percent load, 59^0 F, 60% relative humidity and type of fuel fired to be as follows:"

Rationale: Reflects operations requested by GRU and does not inadvertently limit hours of gas firing.

4) Table - Page 1

Requested Change: a) Add "gas" above "w/PA," b) Revise gas SO2, PM/PM10, CO, H2SO4 emissions, fuel oil NO_x emissions and total emissions as indicated in the table, c) Delete arsenic, and d) Revise regulatory citation from "17-212.400(2)(f)(3)" to "17-212.400(2)(f)(1)."

Rationale: a) Power augmentation is an operating condition while firing natural gas, b) Emission corrections for consistency with Tables 2-1 and 2-5 of the Prevention of Significant Deterioration ("PSD") permit application, c) Arsenic is not a PSD pollutant, and d) Correct citation.

5) NO$_x$ BACT Determination - Page 2

Requested Change: Delete "steam/" on the seventh line.

Rationale: The combustion turbine is equipped with water, not steam, injection for NO$_x$ control.

6) SO2 and H2SO4 BACT Determination - Page 2

Requested Change: Revise as follows: "0.05% sulfur by weight (fuel oil firing), after an equivalent of 55 hours of full load operation at ISO conditions using a fuel oil with a 0.25% sulfur content by weight."

Rationale: GRU requested that DEP allow the existing on-site supply of fuel oil with a 0.25% sulfur content to be used initially until such time as it is drawn down to a minimum practical level. After that the low sulfur (0.05%) fuel oil would be used for the combustion turbine and other existing usages of distillate fuel oil at the Deerhaven Generating Station.

7) BACT Determination Procedure - Page 3, paragraph 2

Requested Change: a) Change "combined cycle power plants" to "simple cycle combustion turbines."

Rationale: The proposed unit is a simple cycle combustion turbine and references to a combined cycle power plant may be a source of confusion.

8) Acid Gases - Nitrogen Oxides, page 3, paragraph 2

Requested Change: Reword the second paragraph by deleting "and water injection" on the second line and changing the last line as follows: "... gas and by water injection to limit emissions to 54 ppmvd..."

Rationale: Clarify that water injection is used to control emissions during fuel oil, not gas, burning.

9) Selective Catalytic Reduction - Page 4, paragraph 1

Requested Change: Revise last sentence as follows:

"As the catalyst ages, the ~~maximum~~ NO_x reduction efficiency (while holding ammonia slip emissions constant) will decrease ~~to approximately 86 percent~~."

Rationale: The ammonia injection rate can be increased to lower NO_x emissions, but the ammonia slip will increase. There is no basis for the generalized percent NO_x reduction.

10) Selective Catalytic Reduction - Page 4, paragraph 4 and 5

Requested Change: a) Change "CTs" to "CT," b) Correct lower range of exhaust temperature from "995" to "955," c) Reword last two sentences of paragraph 4 as follows: "... (reported to operate ~~normally within~~ to a maximum temperature of 1,050°F)."

Rationale: a) Only one unit is proposed, b and c) Consistency with manufacturer's information.

11) Selective Catalytic Reduction - Page 5, paragraph 2

Requested Change: Change on the eighth line "incremented" to "incremental."

Rationale: Grammatical correction.

12) NO_x BACT Determination - Page 5, paragraph 3

Requested Change: Move this paragraph to the section titled BACT Determination by DEP on page 7. GRU requests that the Department explain its basis for stating that a dry low NO_x machine capable of achieving 9 ppm will be available in 1998 or 2.5 years after the combustion turbine's in-service date? How is the availability of a 9 ppm machine with a later in-service date relevant to this unit?

Rationale: The BACT determination discussed on page 5 is the applicant's (GRU's) determination. This paragraph discusses the Department's determination.

13) SO2 and H2SO4 BACT Determination - Page 6, paragraph 1

Requested Change: Delete "(23)."

Rationale: No references are listed.

14) SO2 and H2SO4 BACT Determination - Page 6, paragraph 3

Requested Change: a) Change "Gainesville Utilities" to "Gainesville Regional Utilities," b) Add the following to the last sentence: "...this project, after the equivalent of 55 hours of full load operation at ISO conditions while firing fuel oil with a sulfur content of 0.25% by weight."

Rationale: a) Name correction, b) Allow initially the use of the existing fuel oil supply in the combustion turbine.

15) NO_x Control - Page 7, paragraph 1

Requested Change: a) The cost per ton for controlling NO_x should be changed from "$6,618" to "$6,672.58," b) Delete "at this time" after "BACT" in the last sentence.

Rationale: a) Consistency with page 5 and information provided in GRU's BACT determination, b) See cover letter.

16) NO_x Control - Page 7, paragraph 2

Requested Change: a) The Department should specify the source of its "understanding" of the availability of a 9 ppm machine and the date of such availability, b) Clarify the basis of the statement that 40 CFR 60, Subpart GG "specifies" ISO corrections no later than 1/1/98.

Rationale: a) See cover letter, b) 40 CFR 60 Subpart GG does not require that BACT-based limits be ISO corrected. Corrections are made to demonstrate compliance with the New Source Performance Standards which are considerably higher than the BACT limits.

17) SO2 Control - Page 7

Requested Change: Add the following: "... by weight, after the equivalent of 55 hours of full load operation at ISO conditions while firing fuel oil with a sulfur content of 0.25% by weight."

Rationale: This authorization will permit the consumption of the existing fuel oil supply.

18) <u>BACT Emission Limits - Page 7</u>

Requested Change: Change "Gainesville Utilities" to "Gainesville Regional Utilities".

Rationale: Name correction.

19) <u>NO_x Control - Page 7, paragraph 2</u>

Requested Change: Delete the requirement to correct NO_x emission to ISO conditions as specified in 40 CFR 60, Subpart GG no later than 1/1/98.

Rationale: See cover letter discussion.

20) <u>BACT Emission Limits for NO_x - Page 7, Table</u>

Requested Change: NO_x emissions during oil burning should be changed from "48" to "54" ppmvd and from "190" to "213" lbs/hr as specified in the permit application and GE data sheets.

Rationale: See cover letter.

21) <u>H2SO4 Emission Rate - Page 8</u>

Requested Change: Change the gas emission rate from "2.3" to "2.8" lbs/hr.

Rationale: Typographical error correction for consistency with the PSD Permit application, Table 4-2.

22) <u>Footnote c. - Page 8</u>

Requested Change: Revise as follows: "c. 15 ppmvd/~~48~~<u>54</u> ppmvd at 15% O2, <u>not</u> ISO corrected<u>.</u>~~-as specified in 40 CFR 60, Subpart GG.~~

Rationale: See cover letter.

23) <u>Footnote d. - Page 8</u>

Requested Change: Adjust, as indicated on the marked-up copy, NO_x levels, NO_x Emissions and the table for calculating the NO_x emission allowance to be consistent with 40 CFR 60 Subpart GG.

24) Footnote f. - Page 9

Requested Change: Add "and sulfates" after "mist."

Rationale: Correction of typographical error.

25) Footnote g. - Page 9

Requested Change: Delete "and sulfates" and add "." after "oil."

Rationale: Correction of typographical error.

26) Power Augmentation - Page 9, paragraph 4

Requested Change: a) Revise the second sentence as follows: "Power augmentation allows the firing of ~~additional fuel~~ natural gas with injection of water into the turbine to produce more megawatts during peak-demand periods." b) Clarify that power augmentation is not a violation of a BACT determination, but a request for a separate BACT determination for a different method of operation.

Rationale: a) Provide a correct description of the power augmentation mode, b) Power augmentation is a different method of operation than either natural gas firing or fuel oil firing. Therefore, a separate BACT determination was requested and is appropriate for this mode. It should not be considered a violation of an established BACT for other operating modes.

ATTACHMENT 2

GRU COMMENTS
Conditions of Certification

1) General Operating Requirements - Condition 1

Requested Change: Insert "(based on high heating values of fuel)" after the word "rates" in the first sentence.

Rationale: Clarification as to basis of heat input rates.

2) General Operating Requirements - Condition 6

Requested Change: Delete.

Rationale: This is a Power Plant Siting Act certified plant. Therefore, no separate operating permit is required.

3) Table I - Allowable Emission Limits

Request: a) Delete columns named "TPY(i) and TPY(j)," b) Revise basis of NO_x limits for oil from "48" to "54" ppmvd and lb/hr from "190" to "213." Change total TPY for oil from "190" to "213" and combined TPY from "240.4" to "263.4", c) Revise SO2 emissions for oil (0.25%) in TPY(c) column from "6.0" to "6.6." Change total from "72.7" to "79.3." d) Change SO2 emissions for gas from "2.3" to "2.8."

Rationale: a) Column is not needed as the 3900 hour and 400 hour restrictions does not apply, b) To allow for FBN NO_x emission allowance consistent with 40 CFR 60 Subpart GG. See comments in cover letter, c and d) Correction of typographical and math errors.

4) Table I - Footnotes

Request: a) Add the following at the end of footnote (b): "Hourly emission rates may vary depending on ambient conditions and the CT characteristics. Manufacturer's curves for emission rate correction to other temperatures at different heat input rates shall be provided for DEP review. Subject to approval by the Department for technical validity applying sound engineering principles, the manufacturer's curves shall be used to establish emission rates over a range of temperatures for the purpose of compliance demonstration.", b) Revise footnote (d) as follows: "15 ppmvd/~~48~~54 ppmvd at 15% O2, not ISO corrected ~~as specified in 40 CFR Subpart GG~~, c) In footnote (e) change "48" to "54" ppmvd. Correct NO_x emission levels and formulas for FBN/NO_x allowance and standard as indicated on marked up version, d) Delete footnotes i and j, e) Delete from footnote (c) "with the remaining 1900 hours on natural gas firing."

Rationale: a) Provides for a methodology for determining compliance at non-ISO conditions. See comment in cover letter., b) ISO corrections not appropriate to BACT-based limits. See comment in cover letter., c) See comment in cover letter., d) Footnote is not applicable, d) Not applicable, e) Not necessary.

5) Compliance Determination - Condition 1

Request: a) Change date reference for 40 CFR Appendix A from "July, 1993" to "July 1, 1992," b) Delete references to Methods 1,2 and 3, c) Add frequencies of testing after each method as indicated on marked-up copy, d) Revise frequency of Method 5 to be "I, for fuel oil only. Thereafter, the opacity emissions test may be used unless 10% opacity is exceeded during fuel oil firing." e) Delete requirement for VOC testing and specify that: "Compliance with the total volatile organic compound emission *limits* will be assumed, provided the allowable CO emission rate is achieved; specific VOC compliance testing is not required."

Rationale: a) Consistency with F.A.C. Chapter 17-297.401, b) Methods are inherent to other required methods, c) Clarification. Initial testing only is recommended for H2SO4, CO, and VOC due to the proposed low emission rates, d) The unit will burn distillate fuel oil with minimal particulate emissions. Based on other utilities' experiences, emissions are so low that each test run must be conducted for an extended time (up to 3 hours) to capture sufficient particulate matter on the filters. Allowing opacity to be used as a surrogate can minimize the time and expense of this testing. e) Again, VOC emissions are typically so low from combustion turbines that emissions testing is not warranted. CO serves as an adequate surrogate.

6) Compliance Determination - Condition 3

Request: a) Revise the first line as follows: "During initial performance tests, to determine compliance with the NSPS standard..."

Rationale: a) See comment in cover letter.

7) Compliance Determination - Condition 4

Request: Delete the requirement to incorporate an annually-determined water/fuel ratio into the permit. Specify that the ratio is to be monitored during fuel oil firing only.

Rationale: As long as NO_x concentrations are maintained at the required levels, there is no need to incorporate into the permit an annually-determined water/fuel ratio. The monitoring requirement should apply only when fuel oil is being fired because that is the only time water will be injected for NO_x control.

8) Compliance Determination - Condition 5

Request: Revise as follows:

"5. Test results will be the average of three valid one-hour runs. The DEP Northeast District office will be notified at least 30 days in writing in advance of the initial performance ~~compliance~~ tests and at least 15 days in advance of the annual compliance test(s). This combustion turbine will operate between ~~95%~~ 90% and 100% of maximum ~~capacity~~ heat input rate for the ambient conditions experienced during the compliance test(s). If it is impracticable to test at 90%-100% of the maximum heat input rate, the combustion turbine may be tested at less than 90% of the maximum heat input rate. In this case, subsequent operation is limited to 110% of the tested heat input rate (corrected for ambient conditions) until a new test is conducted. Once the combustion turbine is so limited, operation at a higher capacity is allowed for no more than 15 days for purposes of additional compliance testing to regain the maximum heat input rate. The turbine manufacturer's heat input rates (based on high heating values of fuel) ~~capacity~~ vs temperature (ambient) curve shall be included with the compliance test results. Compliance tests shall be submitted to the Northeast District office no later than 45 days after completion.

Rationale: Operating/testing flexibility.

9) Compliance Determination - Condition 6

Request: a) Revise the first sentence as follows: "Sulfur and nitrogen content and lower heating value of the fuel oil being fired ... in 40 CFR 60.334(b).," b) Delete the second and third lines, c) Delete the requirement for daily records.

Rationale: a,b,c) The combustion turbine will burn pipeline-supplied natural gas whose composition does not vary significantly. This data will be supplied in support of the annual SO2 compliance demonstration as allowed per Condition 2. Therefore, there is no justification for daily recording of the above referenced parameters. c) With respect to fuel oil, 40 CFR 60.334(b) specifies that for turbines supplied from bulk fuel tanks, "the values shall be determined on each occasion that fuel is transferred to the storage tank from any other source." Daily records are not required.

10) Compliance Determination - Condition 7

Request: a) Add "fuel switching" as an operating condition that may generate "acceptable" excess emissions. b) Delete requirement for submittal of best operating practices to the Department. If the requirement is not deleted, rewrite the last sentence as follows:

"The document ... days of implementation~~, and shall include time limitations on excess emissions caused by turbine startup~~."

Rationale: a) Temporary excess emissions may occur when fuel switching due to the inherent shift from operating in a pre-mix mode to water injection and vice versa. b) Excess emissions during startup are already limited to two hours per this condition and F.A.C. 17-210.700 (1). b) The unit will be "tweaked" during initial performance tests to optimize emission control across the range of expected loads. Further adjustments will be made specifically on an as-needed basis and will be per manufacturer's recommendations.

11) Notification, Reporting and Recordkeeping - Condition 1.c.

Request: Delete the last sentence regarding "testing of any instruments."

Rationale: The term "instrument" is ambiguous. The continuous emission monitors will be tested as required per 40 CFR Parts 60 and 75 which already contain provisions for DEP notification.

12) Monitoring Requirements - Condition 1

Request: Change "1993" to "1992."

Rationale: Consistency with F.A.C. Chapter 17-297.401.

13) Monitoring Requirements - Condition 2

Request: Delete "/steam" on the second and third lines.

Rationale: Steam injection is not applicable to this combustion turbine.

14) Rule Requirements - Condition 1

Request: Change "July, 1992" to "July 1, 1992."

Rationale: Consistency with F.A.C. Chapter 17-297.401.

15) Rule Requirements - Condition 3

Request: Revise reference from "17-210.300(1)" to "17-210.300."

Rationale: Rule 17-210.300(1) refers to air construction permits. The combustion turbine is being permitted through the PPSA and therefore, no permit other than these Conditions of Certification are required. Rule 17-210.300 references the general requirements for compliance with federal, state, and local regulations and requirements.

16) Rule Requirements - Condition 6

Request: Change "1993" to "1992."

Rationale: Consistency with F.A.C. Chapter 17-297.401.

17) Rule Requirements - Condition 7

Request: Change rule citation from "17-210.300(2)" to "17-210.370(2)."

Rationale: Correction of typographical error.

18) Rule Requirements - Condition 8. and 9

Request: Delete conditions.

Rationale: The combustion turbine is being permitted through the Power Plant Siting Act. Therefore, these conditions are not applicable.

file

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning

April 20, 1994

RECEIVED

APR 25 1994

Bureau of
Air Regulation

Ms. Teresa Heron
Florida Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Gainesville Regional Utilities
Deerhaven Combustion Turbine 3 Addition
Fuel-Bound Nitrogen Question

Dear Ms. Heron:

This letter is provided in response to our recent conversation regarding the issue of the fuel-bound nitrogen (FBN) in the fuel oil and the associated emissions of NO_x from the proposed combustion turbine. As you know, the emissions of NO_x from combustion turbines are dependent upon a number of factors including the temperature and pressure at which combustion occurs and at the amount of nitrogen bound up in the fuel. Natural gas, the primary fuel proposed for Deerhaven combustion turbine No. 3, has practically no FBN, and distillate fuel oil, which is proposed as the back-up fuel for the Deerhaven combustion turbine, contains very little FBN. However, there is enough FBN in distillate fuels to make a significant difference in the controlled NO_x emission rate. As a result, the New Source Performance Standard (NSPS) for combustion turbines (40 CFR 60 Subpart GG) provides an allowance for this additional FBN in the NO_x emission standard which is dependent on the actual amount of FBN in the distillate fuel.

GRU's request for a maximum FBN allowance of 0.03% is based on conversations with major oil suppliers including Chevron, Amerada Hess, BP Oil, MG Refining and Marketing, Central Oil, and Coastal Fuels. According to these companies, nitrogen content is <u>not</u> a distillate fuel specification and varies with every shipment of crude oil. There currently is no specific removal/blending process to control the nitrogen content of fuel oils as there is for sulfur. Although there was agreement that the FBN of distillate was expected to be fairly low due to the customary refining process, the companies do not routinely analyze for this parameter. As a result, they had insufficient data to provide a "typical" nitrogen analyses. Spot analyses revealed that the content varies significantly, ranging from less than 0.015% to 0.05% or higher. The companies indicated that while they may be able to provide distillate fuel with a FBN of 0.015% on a batch by batch basis, they <u>cannot and will not guarantee</u> it. The customer, therefore, can either accept or reject what is available at the time an oil purchase is needed.

GRU does not believe it is reasonable nor justifiable to impose a limit on the quality of fuel when that quality may not be available and will not be guaranteed by a supplier. Such a limit could put GRU in the untenable position of having to purchase larger quantities of low-FBN fuel than needed just because it is available at a particular time, or of having to curtail operations or exceed allowable limits in the event the specific fuel is not available when needed.

GRU's request for a FBN allowance of 0.03% is reasonable and supportable. The FBN is within the range indicated by the suppliers to be generally available and provides a needed degree of flexibility in fuel purchases and operations.

As to the question of the emission estimate associated with the FBN of 0.03%, please see the attached letter from GE, the combustion turbine supplier for the proposed project. As indicated, the emission rate estimated by GE for firing fuel oil with a FBN of 0.015% is 42 ppmvd at 15% O_2, which is consistent with other recent applications you have seen. Also as indicated, the emission rate estimated by GE for firing fuel oil with a FBN of 0.03% is 54 ppmvd at 15% O_2 (42 ppmvd + 12 ppmvd, the allowance in Subpart GG for this amount of FBN). While this may be slightly different from values you have seen for other combustion turbine projects recently, <u>it is the estimate from the manufacturer</u>. GE indicates that the differences can be accounted for by actual differences in the combustion turbines (i.e., Frame 7FA versus Frame 7EA, the unit selected by GRU) and differences in the emission estimation techniques used on the different projects.

Based on the information available from the combustion turbine manufacturer, GRU believes that the proposed maximum NO_x emission rate of 54 ppmvd at 15% O_2 is reasonable for distillate fuel oil with a FBN of 0.03%, and is consistent with NSPS.

Please call me at (904) 334-3400 ext. 1284 should you have any questions on this material.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Senior Environmental Engineer

YEJ:gm

Attachments

xc: Hamilton Oven, FDEP
Doug Roberts, HBGS
Doug Fulle, EEC
Tom Putnam, ESI
Doug Beck
DHGT3

HERONFBN.Y14

GE Power Generation Engineering

Project Engineering
General Electric Company, Bldg. 53, Suite 200
One River Road, Schenectady, NY 12345 USA
Phone: (518) 385-9219 Dial Comm: 8*235-9219
FAX: (518) 385-7883 FAX Dial Comm: 8*235-7883

Date: April 13, 1994

Copies:

G Amengual	53-401	MM Schorr	2-647
J Hudson	GVL 156	R Gordon	23-113
J Chalfin	22-237	M Cardano	Tampa
LB/File			

Subject: **Gainesville Regional Utilities - MS7001(EA)**
GR0292

To: Tom Putman
Ebasco Services
145 Technology Park
Norcross, GA 30092

Per our telecon earlier today, I am writing to explain that our calculation of an additional 12 ppmvd NO_x at a fuel bound nitrogen level of 0.03%, by weight, in distillate fuel is based on the US EPA NSPS allowance in 40CRF60. Therefore the total NO_x level on distillate is 54 ppmvd @ 15% O_2 (42+12). When fuel bound nitrogen levels are 0.015%, by weight, or less, GE has traditionally not increased reported NO_x levels.

Actual fuel bound nitrogen yields on an MS7001(FA) machine should theoretically be slightly lower, due to higher firing temperature and pressure ratios than an (EA) machine. When reporting additional NO_x due to fuel bound nitrogen levels above 0.015% GE has used several methods, one being the above 40CFR60 allowance. In some cases only the difference between the 0.015% level and another specific level (such as 0.03%) was used depending on the frame size machine, combustor, other fuel characteristics etc. These variations may account for different estimated NO_x levels, at a given fuel bound nitrogen level, on different projects. A new algorithm is now being tested which calculates estimated fuel bound nitrogen yields based on a number of technical parameters. Perhaps this will result in more accurate predictions in the future as we develop new data bases with advanced combustors just now becoming operational.

Michael A. Davi
Michael A. Davi, Senior Program Manager
GT Applications Engineering

md/

Florida Department of

Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

March 28, 1994

Mr. John Bunyak, Chief
Policy, Planning and Permit Review Branch
National Park Service-Air Quality Division
P. O. Box 25287
Denver, CO 80225

Dear Mr. Bunyak:

RE: Gainesville Regional Utilities
Deerhaven Combustion Turbine Addition
Alachua County, PSD-FL-212

The Department has received the above referenced PSD application package. Please review this package and forward your comments to the Department's Bureau of Air Regulation by April 18, 1994. The Bureau's FAX number is (904)922-6979.

If you have any questions, please contact Teresa Heron or Cleve Holladay at (904)488-1344 or write to me at the above address.

Sincerely,

Patricia G. Adams

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

CHF/pa

Enclosures

Florida Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

March 28, 1994

Ms. Jewell A. Harper, Chief
Air Enforcement Branch
U.S. EPA, Region IV
345 Courtland Street, N.E.
Atlanta, Georgia 30308

Dear Ms. Harper:

RE: Gainesville Regional Utiltiies
Deerhaven Combustion Turbine Addition
Alachua County, PSD-FL-212

The Department has received the above referenced PSD application package. Please review this package and forward your comments to the Department's Bureau of Air Regulation by April 18, 1994. The Bureau's FAX number is (904)922-6979.

If you have any questions, please contact Teresa Heron or Cleve Holladay at (904)488-1344 or write to me at the above address.

Sincerely,

Patricia G. Adams

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

CHF/pa

Enclosures

HOPPING BOYD GREEN & SAMS

ATTORNEYS AND COUNSELORS

123 SOUTH CALHOUN STREET

POST OFFICE BOX 6526

TALLAHASSEE, FLORIDA 32314

(904) 222-7500

FAX (904) 224-8551

FAX (904) 681-2964

March 22, 1994

RECEIVED

MAR 22 1994

Bureau of Air Regulation

BY HAND DELIVERY

Mr. Clair Fancy
Bureau of Air Regulation
Department of Environmental Protection
Magnolia Courtyard, Room 127
Tallahassee, FL 32399

Re: Alachua County
City of Gainesville, Gainesville Regional Utilities
Deerhaven Combustion Turbine 3 Project

Dear Mr. Fancy:

Please find enclosed five copies of an application for a federally-required prevention of significant deterioration permit for a nominal 74 megawatt simple cycle combustion turbines to be located within Gainesville Regional Utilities Deerhaven power plant site. The Deerhaven site has been previously certified under the Florida Electrical Power Plant Siting Act. In addition to this application, a companion request for modification of site certification has also been submitted to the Department's Office of Siting Coordination. A fee of $10,000 has been paid to that Office to cover agency review expenses for this project. The computer printouts and computer disks of the air quality modeling results are being sent under separate cover directly to Tom Rogers of DEP.

I will be contacting your staff in a few weeks to review the initial comments your staff may have. In the meantime, please call either Yolanta Jonynas of GRU at (904) 334-3400, ext. 1284 or me if you have any questions.

Sincerely,

Douglas S. Roberts

Douglas S. Roberts

DSR/gs

cc: Preston Lewis, DEP
Hamilton S. Oven, DEP
Doug Beck, GRU
Yolanta Jonynas, GRU
Doug Fulle, Ebasco

Prevention of Significant Deterioration Permit Application

For

GAINESVILLE REGIONAL UTILITIES
Deerhaven Generating Station

COMBUSTION TURBINE ADDITION

GAINESVILLE REGIONAL UTILITIES 301SE 4th Avenue, Gainesville, Florida 32601

March 1994

Prepared By:

ENSERCH ENVIRONMENTAL CORPORATION

Formerly the Environmental Division of Ebasco Services Incorporated
145 Technology Park, Norcross, Georgia 30092-2979

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

GAINESVILLE REGIONAL UTILITIES (GRU) DEERHAVEN GENERATING STATION COMBUSTION TURBINE ADDITION

Gainesville Regional Utilities
301 SE 4th Ave.
Gainesville, FL 32601

March 1994

Prepared by:
ENSERCH Environmental Corporation
formerly the Environmental Division of Ebasco Services Incorporated
145 Technology Park
Norcross, GA 30092

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

N TOWERS OFFICE BUILDING
0 BLAIR STONE ROAD
ALLAHASSEE, FLORIDA 32301

PSD-FL-212

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Combustion Turbine [X] New[1] [ ] Existing[1]

APPLICATION TYPE: [X] Construction [ ] Operation [ ] Modification

COMPANY NAME: City of Gainesville, Gainesville Regional Utilities COUNTY: Alachua

Identify the specific emission point source(s) addressed in this application (i.e. Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) COMBUSTION TURBINE DHCT-3 NAT. GAS/~~DISTILLATE FUEL~~ Oil FIRED

SOURCE LOCATION: Street US 441/SR20/SR25 City Gainesville

UTM: East 365.5 km North 3292.7 km

Latitude 29 ° 45 ' 32 "N Longitude 82 ° 23 ' 26 "W

APPLICANT NAME AND TITLE: Michael L. Kurtz, General Manager for Utilities Gainesville Regional Utilities

APPLICANT ADDRESS: P. O. Box 147117, Station A-134, Gainesville, FL 32614-7117

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of Gainesville Regional Utilities

I certify that the statements made in this application for a Construction permit are true, correct and complete to the best of my knowledge and belief. Further, I agree to maintain and operate the pollution control source and pollution control facilities in such a manner as to comply with the provision of Chapter 403, Florida Statutes, and all the rules and regulations of the department and revisions thereof. I also understand that a permit, if granted by the department, will be non-transferable and I will promptly notify the department upon sale or legal transfer of the permitted establishment.

*Attach letter of authorization

Signed: Michael L. Kurtz

Michael L. Kurtz, General Manager for Utilities
Name and Title (Please Type)

Date: 3/08/94 Telephone No. (904) 334-3400 X1006

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.)

This is to certify that the engineering features of this pollution control project have been ~~designed/~~examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that

[1] See Florida Administrative Code Rule 17-2.100(57) and (104)

the pollution control facilities, when properly maintained and operated, will dischar an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

Signed Darrel J Graziani 3-1-94

Darrel James Graziani
Name (Please Type)

Ebasco Environmental (1)
Company Name (Please Type)

759 SE Federal Highway
Stuart, FL 34994-2936
Mailing Address (Please Type)

Florida Registration No. 0044685 Date: Exp. 2/28/95 Telephone No. (407) 225-8712

SECTION II: GENERAL PROJECT INFORMATION

A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

Installation of a Nominal 74 MW simple cycle combustion turbine (CT) equipped with dry low NO_x combustors for natural gas firing and water injection for fuel oil firing and power augumentation. The CT is expected to operate in full compliance with the applicable regulations.

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction September 1994 Completion of Construction June 1995

C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

N/A

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

Pursuant to the Power Plant Siting Act, the Deerhaven Generating Station is a "Certified Site" (PA 74-04).

(1) Ebasco Environmental is currently in the process of changing its name to Enserch Environmental.

E. Requested permitted equipment operating time: hrs/day_____; days/wk_____; wks/yr_____;

if power plant, hrs/yr 3900; if seasonal, describe:

F. If this is a new source or major modification, answer the following questions. (Yes or No)

1. Is this source in a non-attainment area for a particular pollutant? No

   a. If yes, has "offset" been applied? N/A

   b. If yes, has "Lowest Achievable Emission Rate" been applied? N/A

   c. If yes, list non-attainment pollutants. N/A

2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. Yes(1)

3. Does the State "Prevention of Significant Deterioriation" (PSD) requirement apply to this source? If yes, see Sections VI and VII. Yes(2)

4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? Yes(3)

5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? No

H. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? No

   a. If yes, for what pollutants? N/A

   b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable.

(1) See Section 4.0 of the attached PSD application.

(2) PSD is triggered since the project represents a major modification to a major facility.

(3) 40 CFR 60, Subpart GG - New Source Performance Standards for Stationary Combustion Turbines.

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable: N/A

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		

B. Process Rate, if applicable: (See Section V, Item 1) N/A

1. Total Process Input Rate (lbs/hr): N/A

2. Product Weight (lbs/hr): N/A

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary) See Attachment No. 1

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/yr	T/yr	

[1]See Section V, Item 2.

[2]Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

[3]Calculated from operating rate and applicable standard.

[4]Emission, if source operated without control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4) N/A

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)

E. Fuels
Data Source: GE Data sheets Attachment A. PSD application

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas	40,700#	45,920#	1,096.6
Fuel Oil Distillate #2	50,380#	50,380#	990.6

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.

Avg consumption for Natural Gas represents 100% load at ISO coditions. Max consumption & max heat input represent Natural Gas with power augmentation at 100% load & ISO conditions. Fuel Oil consumption rates represent 100% load at ISO contions.

Fuel Analysis:

Percent Sulfur: NG-10 grs/100 SCF FO-.25/.05 Percent Ash: NG-N/A FO-0.01

Density: NG-1 LB/23.8 SCF FO-7.02 lbs/gal Typical Percent Nitrogen: NG-N/A FO-0.03

Heat Capacity: NG-23,860 FO-19,663 BTU/lb (HHV) BTU/gal

Other Fuel Contaminants (which may cause air pollution): Fuel Oil - Trace Metals Arsenic, Beryllium, Lead, Mercury

F. If applicable, indicate the percent of fuel used for space heating. N/A

Annual Average ______ Maximum ______

G. Indicate liquid or solid wastes generated and method of disposal.

Waste air filters - solid waste to be disposed offsite. Waste lubrication oils - liquid waste to be sent offsite or used for on site energy recovery

See Section 2.0, Tables 2-1 through 2-7, and Appendix A of the PSD Application

H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: 52 ft. Stack Diameter: 14.1 ft.

Gas Flow Rate: 1027653 to 1573615 ACFM 316830 to 541621 DSCFM Gas Exit Temperature: 955 to 1100 °F.

Water Vapor Content: 6.59 to 12.78 % Velocity: 104 to 162 FPS

Ranges provided for operating loads of 60 to 100% and ambient temperatures of 20°F to 95°F

SECTION IV: INCINERATOR INFORMATION N/A

Type of Waste	Type O (Plastics)	Type I (Rubbish)	Type II (Refuse)	Type III (Garbage)	Type IV (Pathological)	Type V (Liq.& Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (lbs/hr)							

Description of Waste ____________________

Total Weight Incinerated (lbs/hr) ________ Design Capacity (lbs/hr) ________

Approximate Number of Hours of Operation per day ______ day/wk ______ wks/yr. ______

Manufacturer ____________________

Date Constructed ____________ Model No. ____________

	Volume $(ft)^3$	Heat Release (BTU/hr)	Fuel		Temperature (°F)
			Type	BTU/hr	
Primary Chamber					
Secondary Chamber					

Stack Height: ______ ft. Stack Diamter: ______ Stack Temp. ______

Gas Flow Rate: ______ ACFM ______ DSCFM* Velocity: ______ FPS

*If 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic foot dry gas corrected to 50% excess air.

Type of pollution control device: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) ____________________

Brief description of operating characteristics of control devices: ____________

____

____

____

____

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

____

____

____

____

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)] N/A

2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made. See Attachments 1 and 2

3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test). See Attachments 1 and 2

4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.) See Section 4, PSD Application

5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency). N/A

6. An 8 1/2" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained. Figure 2-1, PSD Application

7. An 8 1/2" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Example: Copy of relevant portion of USGS topographic map). Figure 1-3, PSD Application

8. An 8 1/2" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram. Figure 2-2, PSD Application

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation. N/A covered under PPSA Modification fee

10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit. N/A

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

[X] Yes [ ] No 40 CFR 60 Subpart GG

Contaminant	Rate or Concentration @ISO
Sulfur Dioxide	Fuel Spec-0.8%S by weight
Sulfur Dioxide	Exhaust Limit-150 ppmvd @ 15% O_2
Nitrogen Oxides	Fuel Oil 105.8 ppmvd @ 15% O_2
Nitrogen Oxides	Natural Gas - 98.5 ppmvd @ 15% O_2

B. Has EPA declared the ~~best available control technology~~ most stringent emission limits for this class of sources (If yes, attach copy)

[XX] Yes [ ] No

Contaminant	Rate or Concentration @ISO
Sulfur Dioxide	Fuel Spec-0.05%S by weight
Nitrogen Oxides	Natural Gas-3.5 ppmvd @ 15% O_2
Nitrogen Oxides	Fuel Oil -11.7ppmvd + FBN Allowance @
	15% O_2

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration @ISO
Sulfur Dioxide	Fuel Spec-0.05%S by weight
Nitrogen Oxides	Natural Gas-15 ppmvd @ 15% O_2
	Natural Gas/ Power Augmentation-30 ppmvd @15% O
	Fuel Oil-42 ppmvd + FBN Allowance @ 15% O_2

D. Describe the existing control and treatment technology (if any).

1. Control Device/System: DLNO_x/wet Injection
2. Operating Principles: Reduce Thermal NO_x
3. Efficiency: 76-90%
4. Capital Costs: N/A

Explain method of determining EPA ACT Document - EPA-453/R-93-007

5. **Useful Life:** 15 yrs

6. **Operating Costs:** N/A

7. **Energy:** N/A

8. **Maintenance Cost:** N/A

9. **Emissions:**

Contaminant	Rate or Concentration
Nitrogen Oxides	Dry Low NO_x - 15 ppmvd (Natural Gas) @ 15% O_2
Nitrogen Oxides	Water Injection-42 +FBN ppmvd (Fuel Oil) @15% O_2
Nitrogen Oxides	Water Injection-30 ppmvd (NG/Power Augmentation)
	@15% O_2

10. **Stack Parameters** See Section 2.0, Tables 2-1 through 2-7 of the PSD Application, App

a. **Height:** ft. b. **Diameter:** ft.

c. **Flow Rate:** ACFM d. **Temperature:** °F.

e. **Velocity:** FPS

E. **Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary).**

1.

a. **Control Device:** SCR

b. **Operating Principles:** Reaction of NH_3

c. **Efficiency:**[1] 80%

d. **Capital Cost:** 6.3 million

e. **Useful Life:** 15 yrs

f. **Operating Cost:** 1.5 million

g. **Energy**[2] .3590 kwh

h. **Maintenance Cost:** Included in f.

i. **Availability of construction materials and process chemicals:** Good

j. **Applicability to manufacturing processes:** N/A

k. **Ability to construct with control device, install in available space, and operate within proposed levels:** Fair

2. N/A

a. **Control Device:**

b. **Operating Principles:**

c. **Efficiency:**[1]

d. **Capital Cost:**

e. **Useful Life:**

f. **Operating Cost:**

g. **Energy:**[2]

h. **Maintenance Cost:**

i. **Availability of construction materials and process chemicals:**

[1]Explain method of determining efficiency. (Act Document EPA 453/R-93-007)
[2]Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

3. N/A

a. Control Device: b. Operating Principles:

c. Efficiency:[1] d. Capital Cost:

e. Useful Life: f. Operating Cost:

g. Energy:[2] h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

4. N/A

a. Control Device: b. Operating Principles:

c. Efficiency:[1] d. Capital Costs:

e. Useful Life: f. Operating Cost:

g. Energy:[2] h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

F. Describe the control technology selected:

1. Control Device: DL NO_x/Water Injection 2. Efficiency:[1] 76-90%

3. Capital Cost: N/A 4. Useful Life: 15 yrs

5. Operating Cost: N/A 6. Energy:[2] N/A

7. Maintenance Cost: N/A 8. Manufacturer: General Electric

9. Other locations where employed on similar processes: Numerous

a. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

[1]Explain method of determining efficiency.
[2]Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems: See Section 4.0 of the PSD Application

[1]Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

A. Company Monitored Data N/A

1. ____________ no. sites ____________ TSP ____________ ( ) SO^{2*} ____________ Wind spd/dir

Period of Monitoring ____/____/____ to ____/____/____
month day year month day year

Other data recorded ____________________________

Attach all data or statistical summaries to this application.

*Specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

a. Was instrumentation EPA referenced or its equivalent? [ ] Yes [ ] No

b. Was instrumentation calibrated in accordance with Department procedures?

[ ] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling Obtained from FDEP

1. 5 Year(s) of data from 1 / 1 / 1985 to 12 / 31 / 1989
month day year month day year

2. Surface data obtained from (location) Gainesville, FL

3. Upper air (mixing height) data obtained from (location) Tampa, FL

4. Stability wind rose (STAR) data obtained from (location) N/A

C. Computer Models Used

1. ISCST2 (93109) No Modified? If yes, attach description.

2. VISCREEN (V1.01) No Modified? If yes, attach description.

3. ______ Modified? If yes, attach description.

4. ______ Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables. Shipped under separate letter.

D. Applicants Maximum Allowable Emission Data (Table 6-2 PSD Application)

Pollutant	Emission Rate @20°F-100% load	
TSP	1.9	grams/sec
SO^2	33.54	grams/sec

E. Emission Data Used in Modeling

See Tables 6-1 and 6-2 in PSD application

Attach list of emission sources. Emission data required is source name, description of point source (on NEDS point number), UTM coordinates, stack data, allowable emissions, and normal operating time.

F. Attach all other information supportive to the PSD review. See PSD Application

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e., jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources. See PSD Application

H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology. See PSD Application

ATTACHMENT NO. 1

AIRBORNE CONTAMINANTS EMITTED

ATTACHMENT No. 1

Airborne Contaminants Emitted

NATURAL GAS FIRING - 100% Load @ 20 °F

NAME OF CONTAMINANT	EMISSION MAXIMUM LBS/HR	EMISSION ACTUAL T/YR	ALLOWED EMISSION RATE PER RULE	ALLOWABLE EMISSION LBS/HR	POTENTIAL EMISSION LBS/HR	POTENTIAL EMISSION T/YR
CO	35	68	N/A	35	35	68
NOX	58	113	BACT	58	58	113
SO2	29	57	BACT	29	29	57
PM10	7	13.7	BACT	7	7	13.7
TSP	7	13.7	N/A	7	7	13.7
VOC	3	5.9	N/A	3	3	5.9
LEAD	N/A	N/A	N/A	N/A	N/A	N/A
BERYLLIUM	N/A	N/A	N/A	N/A	N/A	N/A
MERCURY	N/A	N/A	N/A	N/A	N/A	N/A
H2SO4	3	5.9	BACT	3.0	3.0	5.9
ARSENIC	N/A	N/A	N/A	N/A	N/A	N/A

NATURAL GAS FIRING - POWER AUGMENTATION, 100% Load @ 59 °F

NAME OF CONTAMINANT	EMISSION MAXIMUM LBS/HR	EMISSION ACTUAL T/YR	ALLOWED EMISSION RATE PER RULE	ALLOWABLE EMISSION LBS/HR	POTENTIAL EMISSION LBS/HR	POTENTIAL EMISSION T/YR
CO	42	8.2	N/A	42	42	8.2
NOX	120	23.4	BACT	120	120	23.4
SO2	30	5.8	BACT	30	30	5.8
PM10	7	1.4	BACT	7	7	1.4
TSP	7	1.4	N/A	7	7	1.4
VOC	4.5	0.88	N/A	4.5	4.5	0.88
LEAD	N/A	N/A	N/A	N/A	N/A	N/A
BERYLLIUM	N/A	N/A	N/A	N/A	N/A	N/A
MERCURY	N/A	N/A	N/A	N/A	N/A	N/A
H2SO4	3.1	0.60	BACT	3.1	3.1	0.60
ARSENIC	N/A	N/A	N/A	N/A	N/A	N/A

FUEL OIL FIRING - 100% Load @ 20 °F

NAME OF CONTAMINANT	EMISSION MAXIMUM LBS/HR	EMISSION ACTUAL T/YR	ALLOWED EMISSION RATE PER RULE	ALLOWABLE EMISSION LBS/HR	POTENTIAL EMISSION LBS/HR	POTENTIAL EMISSION T/YR
CO	71	71	N/A	71	71	71
NOX	237	237	BACT	237	237	237
SO2 (0.05%)	53	53	BACT	53	53	53
SO2 (0.25%)	266	266	As Requested	266	266	266
PM10	15	15	BACT	15	15	15
TSP	15	15	N/A	15	15	15
VOC	7	7	N/A	7	7	7
LEAD	0.0638	0.0638	N/A	0.0638	0.0638	0.0638
BERYLLIUM	0.0004	0.0004	N/A	0.0004	0.0004	0.0004
MERCURY	0.001	0.001	N/A	0.001	0.001	0.001
H2SO4 (0.05%)	5.6	5.6	BACT	5.6	5.6	5.6
H2SO4 (0.25%)	27.8	27.8	BACT	27.8	27.8	27.8

SUPPORT CALCULATIONS FOR ATTACHMENT No. 1

Case 1: Natural Gas Firing @ 100% Load and 20 F

Hourly Emission Rates (GE Data Sheets)

CO = 35 lbs/hr PM10 = 7 lbs/hr VOC = 3 lbs/hr

NOx = 58 lbs/hr TSP = 7 lbs/hr

Hourly Emission Rates (Mass Balance)

SO2 emission estimate is based on 10 grains of sulfur per 100 scf of gas, with a gas density of 23.8 scf/lb, a maximum fuel usage rate of 44990 lbs/hr and 95.1 % conversion to SO2.

$$SO2 = (44990)\cdot(23.8)\cdot\frac{10}{100}\cdot\frac{1}{7000}\cdot\frac{64}{32}\cdot\frac{95.1}{100} = 29.094 \quad \text{lbs/hr}$$

H2SO4 emission estimate is based on 10 grains of sulfur per 100 scf of gas, with a gas density of 23.8 scf/lb, a maximum fuel usage rate of 44990 lbs/hr and 6.5 % conversion to H2SO4.

$$H2SO4 = (44990)\cdot(23.8)\cdot\frac{10}{100}\cdot\frac{6.5}{100}\cdot\frac{1}{7000}\cdot\frac{98}{32} = 3.045 \quad \text{lbs/hr}$$

Annual Emission Rates (TPY), Based on 3,900 hours per year.

$$CO = 35\cdot\frac{3900}{2000} = 68.25 \qquad NOX = 58\cdot\frac{3900}{2000} = 113.1 \qquad PM10 = 7\cdot\frac{3900}{2000} = 13.65$$

$$VOC = 3\cdot\frac{3900}{2000} = 5.85 \qquad TSP = 7\cdot\frac{3900}{2000} = 13.65$$

$$SO2 = 29.094\cdot\frac{3900}{2000} = 56.733 \qquad H2SO4 = 3.045\cdot\frac{3900}{2000} = 5.938$$

Case 2: Natural Gas Firing with Power Augmentation @ 100% Load and ISO Conditions

Hourly Emission Rates (GE Data Sheets)

CO = 42 lbs/hr PM10 = 7 lbs/hr VOC = 4.5 lbs/hr

NOx = 120 lbs/hr TSP = 7 lbs/hr

Hourly Emission Rates (Mass Balance)

SO2 emission estimate is based on 10 grains of sulfur per 100 scf of gas, with a gas density of 23.8 scf/lb, a maximum fuel usage rate of 45920 lbs/hr and 95.1 % conversion to SO2.

$$SO2 = (45920)\cdot(23.8)\cdot\frac{10}{100}\cdot\frac{1}{7000}\cdot\frac{64}{32}\cdot\frac{95.1}{100} = 29.696 \quad \text{lbs/hr}$$

H2SO4 emission estimate is based on 10 grains of sulfur per 100 scf of gas, with a gas density of 23.8 scf/lb, a maximum fuel usage rate of 45920 lbs/hr and 6.5 % conversion to H2SO4.

$$H2SO4 = (45920)\cdot(23.8)\cdot\frac{10}{100}\cdot\frac{6.5}{100}\cdot\frac{1}{7000}\cdot\frac{98}{32} = 3.108 \quad \text{lbs/hr}$$

Case 2: Natural Gas Firing with Power Augmentation @ 100% Load and ISO Conditions

Annual Emission Rates (TPY), Based on 390 hours per year.

$CO = 42\cdot\frac{390}{2000} = 8.19$ $NOX = 120\cdot\frac{390}{2000} = 23.4$ $PM10 = 7\cdot\frac{390}{2000} = 1.365$

$VOC = 4.5\cdot\frac{390}{2000} = 0.878$ $TSP = 7\cdot\frac{390}{2000} = 1.365$

$SO2 = 29.696\cdot\frac{390}{2000} = 5.791$ $H2SO4 = 3.108\cdot\frac{390}{2000} = 0.606$

Case 3: Fuel Oil @ 100% Load and 20 F

Hourly Emission Rates (GE Data Sheets)

CO = 71 lbs/hr PM10 = 15 lbs/hr VOC = 7 lbs/hr

NOx = 237 lbs/hr TSP = 15 lbs/hr

Hourly Emission Rates (Mass Balance)

SO2 emission estimates are based on 0.25 and 0.05 percent sulfur in the fuel oil, a maximum fuel usage rate of 55940 lbs/hr and 95.1 % conversion to SO2.

$$SO2= (55940)\cdot\frac{.25}{100}\cdot\frac{64}{32}\cdot\frac{95.1}{100} = 265.995 \quad \text{lbs/hr}$$

$$SO2= (55940)\cdot\frac{.05}{100}\cdot\frac{64}{32}\cdot\frac{95.1}{100} = 53.199 \quad \text{lbs/hr}$$

H2SO4 emission estimates are based on 0.25 and 0.05 percent sulfur in the fuel oil, a maximum fuel usage rate of 55940 lbs/hr and 6.5 % conversion to H2SO4.

$$H2SO4= (55940)\cdot\frac{.25}{100}\cdot\frac{6.5}{100}\cdot\frac{98}{32} = 27.839 \quad \text{lbs/hr}$$

$$H2SO4= (55940)\cdot\frac{.05}{100}\cdot\frac{6.5}{100}\cdot\frac{98}{32} = 5.568 \quad \text{lbs/hr}$$

Trace metal emssion estimates based on a maximum heat input rate of 1100 MMBtu/hr and the emission factors from AP-42, Section 3.1, Table 3.1-7

$$Be = (1100)\cdot\frac{3.3}{10^7}\cdot\frac{2000}{2000} = 3.63\cdot10^{-4} \quad \text{lbs/hr}$$

$$Pb = (1100)\cdot\frac{5.8}{10^5}\cdot\frac{2000}{2000} = 0.064 \quad \text{lbs/hr}$$

$$Hg = (1100)\cdot\frac{9.1}{10^7}\cdot\frac{2000}{2000} = 0.001 \quad \text{lbs/hr}$$

Case 3: Fuel Oil @ 100% Load and 20 F

Annual emissions (TPY) based on 2000 hours of operation per year.

CO = $71 \cdot \frac{2000}{2000} = 71$

VOC = $7 \cdot \frac{2000}{2000} = 7$

PM10 = $15 \cdot \frac{2000}{2000} = 15$

NOX = $237 \cdot \frac{2000}{2000} = 237$

SO2 = $53.199 \cdot \frac{2000}{2000} = 53.199$

SO2 = $265.995 \cdot \frac{2000}{2000} = 265.995$

H2SO4 = $5.568 \cdot \frac{2000}{2000} = 5.568$

H2SO4 = $27.839 \cdot \frac{2000}{2000} = 27.839$

Hg = $0.001 \cdot \frac{2000}{2000} = 0.001$

Pb = $0.064 \cdot \frac{2000}{2000} = 0.064$

Be = $3.63 \cdot 10^{-4} \cdot \frac{2000}{2000} = 3.63 \cdot 10^{-4}$

ATTACHMENT NO. 2

SUPPLEMENTAL REQUIREMENTS

Emission Estimate Basis:

For the CT, the emission estimate was based on 3900 hours of operation a year at ISO conditions. ISO conditions are slightly lower than the annual averages for the Gainesville area. It is expected that use of the ISO conditions will produce slightly higher annual emission estimates. Since the CT can fire natural gas or fuel oil, worst case emissions are based on a combination of operating scenarios. The highest emissions were determined based on the following operating schedule:

Natural Gas Firing - 1510 hrs/yr
Natural Gas Firing with Power Augmentation - 390 hrs/yr
Fuel Oil Firing - 2000 hrs/yr

Emission data were obtain from either the GE data sheets or AP-42. Sulfur dioxide and sulfuric acid mist emissions are being estimated based on 0.25 and 0.05% sulfur by weight content of the fuel oil. Potential emissions are being set equal to actual emissions for purposes of the estimate. Purpose of this emission calculation is to determine PSD applicability. Maximum emissions reflect operation at 100 percent load and an ambient temperature of 20 F, except for NGF/PA which is at 100 % load and ISO conditions. Average emissions reflect operation at 100 percent load and ISO conditions.

Emission Rates:

Carbon Monoxide
Maximum (lbs/hr) NGF - 35, NGF/PA - 42, FOF - 71 (GE data sheets)
Average (lbs/hr) NGF - 32, NGF/PA - 42, FOF - 65 (GE data sheets)

Actual = Potential (TPY)

$$\frac{(32\cdot1510)+(42\cdot390)+(65\cdot2000)}{2000}=97.35$$

Nitrogen Oxides
Maximum (lbs/hr) NGF - 58, NGF/PA - 120, FOF - 237 (GE data sheets)
Average (lbs/hr) NGF - 53, NGF/PA - 120, FOF - 213 (GE data sheets)

Actual = Potential (TPY)

$$\frac{(53\cdot1510)+(120\cdot390)+(213\cdot2000)}{2000}=276.415$$

Paticulate Matter (PM10)
Maximum (lbs/hr) NGF - 7, NGF/PA - 7, FOF - 15 (GE data sheets)
Average (lbs/hr) NGF - 7, NGF/PA - 7, FOF - 15 (GE data sheets)

Actual = Potential (TPY)

$$\frac{(7\cdot1510)+(7\cdot390)+(15\cdot2000)}{2000}=21.65$$

Total Suspended Paticulate (TSP)
Maximum (lbs/hr) NGF - 7, NGF/PA - 7, FOF - 15 (GE data sheets)
Average (lbs/hr) NGF - 7, NGF/PA - 7, FOF - 15 (GE data sheets)

Actual = Potential (TPY)

$$\frac{(7\cdot1510)+(7\cdot390)+(15\cdot2000)}{2000}=21.65$$

Volatile Organic Compounds (VOC)
Maximum (lbs/hr) NGF - 3, NGF/PA - 4.5, FOF - 7 (GE data sheets)
Average (lbs/hr) NGF - 2.8, NGF/PA - 4.5, FOF - 6 (GE data sheets)

Actual = Potential (TPY)

$$\frac{(2.8\cdot 1510) + (4.5\cdot 390) + (6\cdot 2000)}{2000} = 8.992$$

Sulfur Dioxide (SO2)
Maximum (lbs/hr) NGF - 29.094, NGF/PA - 29.696, FOF - 266 (Mass Balance)
Average (lbs/hr) NGF - 26.32, NGF/PA - 29.696, FOF - 239.557 (Mass Balance)

Actual = Potential (TPY)

$$\frac{(26.32\cdot 1510) + (29.696\cdot 390) + (239.557\cdot 2000)}{2000} = 265.219 \quad \textbf{SO2 @ 0.25\%}$$

$$\frac{(26.32\cdot 1510) + (29.696\cdot 390) + \frac{239.557}{5}\cdot 2000}{2000} = 73.574 \quad \textbf{SO2 @ 0.05\%}$$

Sulfuric Acid Mist (H2SO4)
Maximum (lbs/hr) NGF - 3.045, NGF/PA - 3.108, FOF - 27.839 (Mass Balance)
Average (lbs/hr) NGF - 2.755, NGF/PA - 3.108, FOF - 25.072 (Mass Balance)

Actual = Potential (TPY)

$$\frac{(2.755\cdot 1510) + (3.108\cdot 390) + (25.072\cdot 2000)}{2000} = 27.758 \qquad \textbf{H2SO4 @ 0.25\%}$$

$$\frac{(2.755\cdot 1510) + (3.108\cdot 390) + \frac{25.072}{5}\cdot 2000}{2000} = 7.7 \qquad \textbf{H2SO4 @ 0.05\%}$$

Beryllium (Be)
Maximum (lbs/hr) NGF - Neg., NGF/PA - Neg., FOF - 0.00036 (AP-42)
Average (lbs/hr) NGF - Neg., NGF/PA - Neg., FOF - 0.000327 (Ap-42)

Actual = Potential (TPY)

$$\frac{(0\cdot 1510) + (0\cdot 390) + (0.000327\cdot 2000)}{2000} = 3.27\cdot 10^{-4}$$

Lead (Pb)
Maximum (lbs/hr) NGF - Neg., NGF/PA - Neg., FOF - 0.0638 (AP-42)
Average (lbs/hr) NGF - Neg., NGF/PA - Neg., FOF - 0.0575 (Ap-42)

Actual = Potential (TPY)

$$\frac{(0\cdot 1510) + (0\cdot 390) + (0.0575\cdot 2000)}{2000} = 0.058$$

Mercury (Hg)
Maximum (lbs/hr) NGF - Neg., NGF/PA - Neg., FOF - 0.001 (AP-42)
Average (lbs/hr) NGF - Neg., NGF/PA - Neg., FOF - 0.0000901 (Ap-42)

Actual = Potential (TPY)

$$\frac{(0\cdot 1510) + (0\cdot 390) + (0.000901\cdot 2000)}{2000} = 9.01\cdot 10^{-4}$$

Mass Balance Calculations

Sulfur Dioxide: Natural Gas - 10 grains of sulfur per 100 SCF of gas @ 23.8 SCF/lb., with 95.1 % conversion
Maximum Usage - 44990 lbs/hr
Average Usage - 40700 lbs/hr
Power Augmentation - 45920 lbs/hr
Fuel Oil - 0.25 and 0.05% sulfur by weight, with 95.1 % conversion
Maximum Usage - 55940 lbs/hr
Average Usage - 50380 lbs/hr

MW (S) = 32; MW (SO2) = 64: MW (H2SO4) = 98

Natural Gas:

$$\text{Max. (lbs/hr)} = (44990)\cdot(23.8)\cdot\frac{10}{100}\cdot\frac{1}{7000}\cdot\frac{64}{32}\cdot\frac{95.1}{100} = 29.094$$

$$\text{Ave. (lbs/hr)} = (40700)\cdot(23.8)\cdot\frac{10}{100}\cdot\frac{1}{7000}\cdot\frac{64}{32}\cdot\frac{95.1}{100} = 26.32$$

$$\text{PA (lbs/hr)} = (45920)\cdot(23.8)\cdot\frac{10}{100}\cdot\frac{1}{7000}\cdot\frac{64}{32}\cdot\frac{95.1}{100} = 29.696$$

Fuel Oil:

$$\text{Max. (lbs/hr) @ 0.25\%} = (55940)\cdot\frac{0.25}{100}\cdot\frac{64}{32}\cdot\frac{95.1}{100} = 265.995 \qquad \text{Max @ 0.05\%} = \frac{265.996}{5} = 53.199$$

$$\text{Ave. (lbs/hr) @ 0.25\%} = (50380)\cdot\frac{0.25}{100}\cdot\frac{64}{32}\cdot\frac{95.1}{100} = 239.557 \qquad \text{Ave @ 0.05\%} = \frac{239.557}{5} = 47.911$$

H2SO4: Natural Gas - 10 grains of sulfur per 100 SCF of gas @ 23.8 SCF/lb.
with 6.5 % of the sulfur converted to H2SO4
Maximum Usage - 44990 lbs/hr
Average Usage - 40700 lbs/hr
Power Augmentation - 45920 lbs/hr
Fuel Oil - 0.25 and 0.05% sulfur by weight with 6.5% of the sulfur converted to H2SO4.
Maximum Usage - 55940 lbs/hr
Average Usage - 50380 lbs/hr
MW (S) = 32; MW (SO2) = 64: MW (H2SO4) = 98

Natural Gas:

Max. (lbs/hr) = $(44990)\cdot(23.8)\cdot\left(\frac{10}{100}\right)\cdot\left(\frac{1}{7000}\right)\cdot\left(\frac{98}{32}\right)\cdot\left(\frac{6.5}{100}\right) = 3.045$

Ave. (lbs/hr) = $(40700)\cdot(23.8)\cdot\left(\frac{10}{100}\right)\cdot\left(\frac{1}{7000}\right)\cdot\left(\frac{98}{32}\right)\cdot\left(\frac{6.5}{100}\right) = 2.755$

PA (lbs/hr) = $(45920)\cdot(23.8)\cdot\left(\frac{10}{100}\right)\cdot\left(\frac{1}{7000}\right)\cdot\left(\frac{98}{32}\right)\cdot\left(\frac{6.5}{100}\right) = 3.108$

Fuel Oil:

Max. (lbs/hr) @ 0.25% = $(55940)\cdot\left(\frac{0.25}{100}\right)\cdot\left(\frac{98}{32}\right)\cdot\left(\frac{6.5}{100}\right) = 27.839$ Max @ 0.05% = $\frac{27.839}{5} = 5.568$

Ave. (lbs/hr) @ 0.25% = $(50380)\cdot\left(\frac{0.25}{100}\right)\cdot\left(\frac{98}{32}\right)\cdot\left(\frac{6.5}{100}\right) = 25.072$ Ave @ 0.05% = $\frac{25.072}{5} = 5.014$

AP-42 Calculations

Emission Factors:
- Beryllium = 3.3E-7 lbs/mmBtu
- Lead = 5.8E-5 lbs/mmBtu
- Mercury = 9.1 E-7 lbs/mmBtu

Heat Input Rates:
- FOF (Max.) = 1100 mmBtu/hr
- FOF (Ave.) = 990.6 mmBtu/hr

Beryllium

Max. (lbs/hr) = $(1100)\cdot\left(\frac{3.3}{10^7}\right) = 3.63\cdot10^{-4}$

Ave. (lbs/hr) = $(990.6)\cdot\left(\frac{3.3}{10^7}\right) = 3.269\cdot10^{-4}$

Lead

Max. (lbs/hr) = $(1100)\cdot\left(\frac{5.8}{10^5}\right) = 0.0638$

Ave. (lbs/hr) = $(990.6)\cdot\left(\frac{5.8}{10^5}\right) = 0.0575$

Mercury

Max. (lbs/hr) = $(1100)\cdot\left(\frac{9.1}{10^7}\right) = 0.001$

Ave. (lbs/hr) = $(990.6)\cdot\left(\frac{9.1}{10^7}\right) = 9.014\cdot10^{-4}$

SUPPORT CALCULATIONS FOR THE AIR TOXICS ANALYSIS

References: AP-42, Supplement F, Section 3.1, Table 3-7 and
Air Emissions Species Manual,
Volume I Volatile Organic Compound Species Profiles,
Second Edition, Profile 0007

Basis: AP-42 provides emission factors for various trace metals emitted during the firing of distillate fuel oil. In addition, AP-42 identifies formaldehyde emissions from natural gas fired units equipped with Select Catalytic Reduction. Since the AP-42 trace metal emission factors are based on heat input rates of the combustion turbine the air toxics analysis focused on the maximum heat input rate. For fuel oil firing this maximum heat input rate cooresponds to the 100 % load at 20 F operating case. For the formaldehyde emissions, review of the Species Manual indicates a 30/70 split of the VOC emissions between formaldehyde and methane. For natural gas firing the maximum VOC emissions correspond to the 100 % load at ISO conditions. All VOC emissions were assumed to be formaldehyde for a conservative approach.

Trace Metal Emissions:

Maximum Heat Input Rate: 1100 mmBtu/hr @ 100% load and 20 F (GE Data Sheets)

Antimony (grams/sec)

$$(1100)\cdot\left(\frac{2.2}{10^5}\right)\cdot\left(\frac{454}{3600}\right)=3.05\cdot 10^{-3}$$

Arsenic (grams/sec)

$$(1100)\cdot\left(\frac{4.9}{10^6}\right)\cdot\left(\frac{454}{3600}\right)=6.8\cdot 10^{-4}$$

Beryllium (grams/sec)

$$(1100)\cdot\left(\frac{3.3}{10^7}\right)\cdot\left(\frac{454}{3600}\right)=4.58\cdot 10^{-5}$$

Cadmium (grams/sec)

$$(1100)\cdot\left(\frac{4.2}{10^6}\right)\cdot\left(\frac{454}{3600}\right)=5.83\cdot 10^{-4}$$

Chromium (grams/sec)

$$(1100)\cdot\left(\frac{4.7}{10^5}\right)\cdot\left(\frac{454}{3600}\right)=6.52\cdot 10^{-3}$$

Lead (grams/sec)

$$(1100)\cdot\left(\frac{5.8}{10^5}\right)\cdot\left(\frac{454}{3600}\right)=8.05\cdot 10^{-3}$$

Managese (grams/sec)

$$(1100)\cdot\left(\frac{3.4}{10^4}\right)\cdot\left(\frac{454}{3600}\right)=4.72\cdot 10^{-2}$$

Mercury (grams/sec)

$$(1100)\cdot\left(\frac{9.1}{10^7}\right)\cdot\left(\frac{454}{3600}\right)=1.26\cdot 10^{-4}$$

Selenium (grams/sec)

$$(1100)\cdot\left(\frac{5.3}{10^6}\right)\cdot\left(\frac{454}{3600}\right)=7.35\cdot 10^{-4}$$

Nickel (grams/sec)

$$(1100)\cdot\left(\frac{1.2}{10^3}\right)\cdot\left(\frac{454}{3600}\right)=1.66\cdot 10^{-1}$$

Cobalt (grams/sec)

$$(1100)\cdot\left(\frac{9.1}{10^6}\right)\cdot\left(\frac{454}{3600}\right)=1.26\cdot 10^{-3}$$

Formaldehyde emissions are being estimated based on the maximum VOC emission rate during natural gas firing. This cooresponds to the power augmentation mode at iso conditions. From the GE data sheets the maximum VOC emission rate is 4.5 pounds per hour. For this analysis all VOC emissions are assumed to be formaldehyde.

Formaldehyde (grams/sec)

$$(4.5)\cdot\left(\frac{454}{3600}\right) = 5.68\cdot 10^{-1}$$

Maximum 8-hour, 24-hour and annual impacts are based on the results of the dispersion modelling runs for particulate matter (ISC2 - Model). These maximum impacts which correpond to a 1 gram per second emission rate are as follows:

8-hour (ug/m3) = 0.13702
24-hour (ug/m3) = 0.06108
Annual (ug/m3) = 0.00313

For the CT emissions the maximum impacts are determined by mutipling the maximum emission rate by the maximum impact for the short term averaging periods. The long term impacts are scaled by factors of 2000/8760 and 3900/8760 for fuel oil firing and natural gas firing, respectively.

Hazardous Air Pollutant Impacts:

Formaldehyde:

8-hour (ug/m3)

$$\left[\frac{(5.68)}{10^1}\right]\cdot(0.13702) = 7.78\cdot 10^{-2}$$

24-hour (ug/m3)

$$\left(\frac{05.68}{10^1}\right)\cdot(0.06108) = 3.47\cdot 10^{-2}$$

Annual (ug/m3)

$$\left(\frac{05.68}{10^1}\right)\cdot(0.00313)\cdot\left(\frac{3900}{8760}\right) = 7.92\cdot 10^{-4}$$

Antimony:

8-hour (ug/m3)

$$\left(\frac{03.05}{10^3}\right)\cdot(0.13702) = 4.18\cdot 10^{-4}$$

24-hour (ug/m3)

$$\left(\frac{03.05}{10^3}\right)\cdot(0.06108) = 1.86\cdot 10^{-4}$$

Annual (ug/m3)

$$\left(\frac{03.05}{10^3}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 2.18\cdot 10^{-6}$$

Arsenic:

8-hour (ug/m3)

$$\left(\frac{6.8}{10^4}\right)\cdot(0.13702) = 9.32\cdot 10^{-5}$$

24-hour (ug/m3)

$$\left(\frac{6.8}{10^4}\right)\cdot(0.06108) = 4.15\cdot 10^{-5}$$

Annual (ug/m3)

$$\left(\frac{6.8}{10^4}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 4.86\cdot 10^{-7}$$

Beryllium:

8-hour (ug/m3)

$$\left(\frac{4.58}{10^5}\right)\cdot(0.13702) = 6.28\cdot 10^{-6}$$

24-hour (ug/m3)

$$\left(\frac{4.58}{10^5}\right)\cdot(0.06108) = 2.8\cdot 10^{-6}$$

Annual (ug/m3)

$$\left(\frac{4.58}{10^5}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 3.27\cdot 10^{-8}$$

Cadmium:

8-hour (ug/m3)

$$\left(\frac{5.83}{10^4}\right)\cdot(0.13702) = 7.988\cdot 10^{-5}$$

24-hour (ug/m3)

$$\left(\frac{5.83}{10^4}\right)\cdot(0.06108) = 3.561\cdot 10^{-5}$$

Annual (ug/m3)

$$\left(\frac{5.83}{10^4}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 4.1662\cdot 10^{-7}$$

Chromium:

8-hour (ug/m3)

$$\left(\frac{6.53}{10^3}\right)\cdot(0.13702) = 8.95\cdot 10^{-4}$$

24-hour (ug/m3)

$$\left(\frac{6.53}{10^3}\right)\cdot(0.06108) = 3.99\cdot 10^{-4}$$

Annual (ug/m3)

$$\left(\frac{6.53}{10^3}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 4.67\cdot 10^{-6}$$

Cobalt:

8-hour (ug/m3)

$$\left(\frac{1.26}{10^3}\right)\cdot(0.13702) = 1.73\cdot 10^{-4}$$

24-hour (ug/m3)

$$\left(\frac{1.26}{10^3}\right)\cdot(0.06108) = 7.7\cdot 10^{-5}$$

Annual (ug/m3)

$$\left(\frac{1.26}{10^3}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 9\cdot 10^{-7}$$

Lead:

8-hour (ug/m3)

$$\left(\frac{8.05}{10^3}\right)\cdot(0.13702) = 1.1\cdot 10^{-3}$$

24-hour (ug/m3)

$$\left(\frac{8.05}{10^3}\right)\cdot(0.06108) = 4.92\cdot 10^{-4}$$

Annual (ug/m3)

$$\left(\frac{8.05}{10^3}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 5.75\cdot 10^{-6}$$

Manganese:

8-hour (ug/m3)

$$\left(\frac{4.72}{10^2}\right)\cdot(0.13702) = 6.47\cdot 10^{-3}$$

24-hour (ug/m3)

$$\left(\frac{4.72}{10^2}\right)\cdot(0.06108) = 2.88\cdot 10^{-3}$$

Annual (ug/m3)

$$\left(\frac{4.72}{10^2}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 3.37\cdot 10^{-5}$$

Mercury:

8-hour (ug/m3)

$$\left(\frac{1.26}{10^4}\right)\cdot(0.13702) = 1.73\cdot 10^{-5}$$

24-hour (ug/m3)

$$\left(\frac{1.26}{10^4}\right)\cdot(0.06108) = 7.7\cdot 10^{-6}$$

Annual (ug/m3)

$$\left(\frac{1.26}{10^4}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 9\cdot 10^{-8}$$

Nickel:

8-hour (ug/m3)

$$\left(\frac{1.66}{10^1}\right)\cdot(0.13702) = 2.27\cdot 10^{-2}$$

24-hour (ug/m3)

$$\left(\frac{1.66}{10^1}\right)\cdot(0.06108) = 1.01\cdot 10^{-2}$$

Annual (ug/m3)

$$\left(\frac{1.66}{10^1}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 1.19\cdot 10^{-4}$$

Selenium:

8-hour (ug/m3)

$$\left(\frac{7.35}{10^4}\right)\cdot(0.13702) = 1.01\cdot 10^{-4}$$

24-hour (ug/m3)

$$\left(\frac{7.35}{10^4}\right)\cdot(0.06108) = 4.49\cdot 10^{-5}$$

Annual (ug/m3)

$$\left(\frac{7.35}{10^4}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 5.25\cdot 10^{-7}$$

TABLE 3.1-7. TRACE ELEMENT EMISSION FACTORS FOR DISTILLATE OIL-FIRED GAS TURBINES[a]
(Source Classification Code: 20100101)

EMISSION FACTOR RATING: E[b]

Trace Element	pg/J	lb/MMBtu
Aluminum	64	1.5 E-04
Antimony	9.4	2.2 E-05
Arsenic	2.1	4.9 E-06
Barium	8.4	2.0 E-05
Beryllium	.14	3.3 E-07
Boron	28	6.5 E-05
Bromine	1.8	4.2 E-06
Cadmium	1.8	4.2 E-06
Calcium	330	7.7 E-04
Chromium	20	4.7 E-05
Cobalt	3.9	9.1 E-06
Copper	578	1.3 E-03
Iron	256	6.0 E-04
Lead	25	5.8 E-05
Magnesium	100	2.3 E-04
Manganese	145	3.4 E-04
Mercury	.39	9.1 E-07
Molybdenum	3.6	8.4 E-06
Nickel	526	1.2 E-03
Phosphorus	127	3.0 E-04
Potassium	185	4.3 E-04
Selenium	2.3	5.3 E-06
Silicon	575	1.3 E-03
Sodium	590	1.4 E-03
Tin	35	8.1 E-05
Vanadium	1.9	4.4 E-06
Zinc	294	6.8 E-04

[a]Reference 1.
[b]Emission factor rating of "E" indicates that the data are from a limited data set and may not be representative of a specific source or population of sources.

VOC Profile Speciation Report

Profile Name : Natural Gas Turbine
Profile Number : 0007
Data Quality : C

Control Device : Uncontrolled
Reference(s) : 58, 59
Data Source : Composite profile developed using data based on GC/MS analysis of fuel combustion exhaust.

SCC Assignments: 20200201

Saroad	CAS Number	Name	Spec_MW	Spec_WT	Peak
43201	74-82-8	METHANE	16.04	70.00	
43502	50-00-0	FORMALDEHYDE	30.03	30.00	
TOTAL				100.00	

SUPPORT CALCULATIONS FOR THE BACT DETERMINATION

The BACT analysis focused on the addition of a Selective Catalytic Reduction (SCR) system equipped with a high temperature zeolite catalyst and an air injection system to reduce emission of nitrogen oxides. The base equipment cost estimate was provided by the Norton ChemicalProcess Products Corporation and is the basis of the cost estimate. The most stringent emission limits were set at 3.5 and 11.7 ppmvd @ 15 % O2 for natural gas firing and fuel oil firing respectively. Option #1 estimates emissions based on the application of a SCR system which can reduce emissions levels from 15/30/54 ppm @ 15 % O2 to those of the most stringent emission limits identified by the BACT analysis. Option #2 estimates emissions based on the use of dry low NOx combustors for NGF and water injection for NGF/PA and FOF.

Operating Schedule
NGF - 1510 hrs/yr
NGFPA - 390 hrs/yr
FOF - 2000 hrs/yr

Option #1 Estimated Emission Levels

NGF (lbs/hr)	NGFPA (lbs/hr)	FOF (lbs/hr)
$(53)\cdot\frac{3.5}{15} = 12.37$	$(120)\cdot\frac{3.5}{30} = 14$	$(213)\cdot\frac{11.7}{54} = 46.15$

For emission estimating purposes the emission rates from the GE data sheets were merely scaled to reflect the Option # 1 emission limits.

Option # 2 Emission Levels

NGF (lbs/hr)	NGFPA (lbs/hr)	FOF (lbs/hr)
53	120	213

Emission estimates based on the GE data sheets.

Annual Emission Levels

Option # 1

$$\text{TPY} = \frac{(12.367)\cdot(1510) + (14)\cdot(390) + (46.15)\cdot 2000}{2000} = 58.22$$

Option # 2

$$\text{TPY} = \frac{((53)\cdot(1510) + (120)\cdot 390) + (213)\cdot 2000}{2000} = 276.42$$

Net Reduction (TPY)

$276.42 - 58.22 = 218.2$

Incremental Cost Effectiveness

Total Annual Costs (1993 $) = 1,455,957.53
Total Net Reductions (TPY) = 218.2

$$\text{Incremental Cost Effectiveness (\$/Ton)} = \frac{1455957.53}{218.2} = 6672.58$$

SUPPORT CALCULATION FOR SULFUR CONVERSION RATES

The GE data sheets have provided emission estimates of sulfur dioxide (SO2) for the fuel oil firing mode These emission estimates were based on a certain percentage of sulfur in the fuel oil being converted to SO2. In order to ensure consistency with the GE data these conversion factors were calculated and applied to natural gas firing as well as fuel oil.

Knowns: At 100% load, 95F and a relative humidity of 50 %, the maximum fuel oil flow is 44940 lbs/hr.
At these conditions H2SO4 = 41 lbs/hr, SO2= 393 lbs/hr and SO3=25 lbs/hr.
These emission rates correspond to a fuel oil sulfur content of 0.46% by weight
MW(S)=32, MW(SO2)=64, MW(H2SO4)=98, MW(SO3)=80

Reactions:

S + O2 = SO2	1:1 mole ratio
S + (3/2)O2 = SO3	1:1 mole ratio
SO3 + H2O = H2SO4	1:1 mole ratio

Calculations:

Maximum available sulfur for conversion:

$$(44940)\cdot\frac{0.46}{100} = 206.724 \quad \text{lbs/hr}$$

Sulfur converted for SO2 formation:

$$(393)\cdot\frac{32}{64} = 196.5 \quad \text{lbs/hr} \qquad \frac{196.5}{206.724} = 0.951 \quad \text{Fraction}$$

Sulfur converted for SO3 formation:

$$(25)\cdot\frac{32}{80} = 10 \quad \text{lbs/hr} \qquad \frac{10}{206.724} = 0.048 \quad \text{Fraction}$$

Sulfur converted for H2SO4 formation:

$$(41)\cdot\frac{32}{98} = 13.388 \quad \text{lbs/hr} \qquad \frac{13.388}{206.724} = 0.065 \quad \text{Fraction}$$

Total fraction of sulfur converted:

$$0.951 + 0.048 + 0.065 = 1.064$$

This relates to 95.1 % of the available sulfur being converted to SO2. The remaining fractions are conservative estimates for SO3 and H2SO4 formation.

SUPPORT CALCULATIONS FOR NSPS EMISSION LIMITATIONS

This calculation examines the allowable emission rates pursuant to 40 CFR 60, Subpart GG - New Source Performance Standards for Stationary Gas Turbines.

Natural Gas Lower Heating Value (Btu/lb) = 21,157.82
Fuel Oil Lower Heating Value (Btu/lb) = 18,550
Fuel Oil Fuel Bound Nitrogen Content = 0.03 % by weight
Fuel Oil Sulfur Content = 0.25 % by weight

Natural Gas Firing at ISO conditions and 100 % load:
Natural Gas Flow Rate (lbs/hr) = 40,700
Gross Output (kW) = 82,810

Natural Gas Firing with Power Aug. at ISO conditions and 100 % load:
Natural Gas Flow Rate (lbs/hr) = 45,920
Gross Output (kW) = 89,580

Fuel Oil Firing at ISO conditions and 100 % load:
Fuel Oil Flow Rate (lbs/hr) = 50,380
Gross Output (kW) = 85,580

NSPS NOx Limitation
STD = 0.0075 X (14.4/Y) + F
STD - Standard in percent volume at 15 % O2
Y - Heat Rate (kilojoules per watt hour)
F - Fuel Bound Nitrogen Allowance
F = 0.040 X maximum fuel bound nitrogen content

Calculate Y

NGF $$Y = (40700)\cdot(21157.8215)\cdot\frac{1054.35}{1000}\cdot\frac{1}{1000}\cdot\frac{1}{82810} = 10.964$$

NGF/PA $$Y = (45920)\cdot(21157.8215)\cdot\frac{1054.35}{1000}\cdot\frac{1}{1000}\cdot\frac{1}{89580} = 11.435$$

FOF $$Y = (50380)\cdot(18550)\cdot\frac{1054.35}{1000}\cdot\frac{1}{1000}\cdot\frac{1}{85580} = 11.514$$

Emission Limitations (% volume at ISO conditions and corrected to 15 % O2)

NGF $$(0.0075)\cdot\frac{14.4}{10.964} + 0 = 0.00985$$

NGF/PA $$(0.0075)\cdot\frac{14.4}{11.435} + 0 = 0.00944$$

FOF $$(0.0075)\cdot\frac{14.4}{11.514} + 0.040\cdot(.03) = 0.01058$$

Conversion Factors:

1000 joules/kilojoule
1054.35 joules/Btu
1000 watts/kilowatt

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION FOR GAINESVILLE REGIONAL UTILITIES (GRU) DEERHAVEN GENERATING STATION COMBUSTION TURBINE ADDITION

Gainesville Regional Utilities
301 SE 4th Ave.
Gainesville, FL 32601

March 1994

Prepared by:
ENSERCH Environmental Corporation
formerly the Environmental Division of Ebasco Services Incorporated
145 Technology Park
Norcross, GA 30092

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EXECUTIVE SUMMARY

Gainesville Regional Utilities (GRU) is planning to install a 74 MW (nominal), dual fuel, simple cycle combustion turbine (CT) at its existing Deerhaven Site approximately seven miles north of Gainesville, in Alachua County. The existing Deerhaven Station consists of two steam generating units (a nominal 81 MW gas/oil fired unit (Unit 1) and a nominal 235 MW coal-fired unit (Unit 2)), and two nominal 22 MW gas/oil fired CTs. The addition of the new CT is being treated as a modification to the existing site certification (PA74-04) under Florida Power Plant Siting Act Chapter 403 Part II, F.S. based upon its location within a "certified site". This Prevention of Significant Deterioration (PSD) Application is being submitted in conjunction with the modification request.

The selected CT, designated as DHCT3, is a General Electric (GE) Model MS7001EA dry low NO_x combustor unit which will fire natural gas as the primary fuel and low sulfur distillate fuel oil as a backup fuel. The unit will function as an intermediate peaking unit and will operate up to a maximum of 3,900 hours per year.

Under federal and Florida Department of Environmental Protection (FDEP) PSD regulations, all major new sources or modifications of major existing sources located in attainment areas must undergo the following analyses for each pollutant emitted in significant quantities: (1) a control technology analysis; (2) an air quality impacts analysis; and (3) an additional impacts analysis. The source must also be reviewed with respect to Good Engineering Practice (GEP) stack height limitations, compliance with New Source Performance Standards (NSPS), and compliance with state emission limits. The control technology analysis consists of a demonstration that the Best Available Control Technology (BACT) will be used to limit pollutant emissions. The air quality impacts analysis involves an assessment of the existing air quality and an analysis of whether the impacts of the proposed source will comply with the allowable Ambient Air Quality Standards (AAQS) and not cause exceedances of the allowable PSD increments either in the site vicinity or in any nearby Class I PSD areas.

The proposed project is located in an attainment area and is thus subject to the PSD permitting requirements. It is considered a major modification to a major existing source and is subject to PSD review for the following pollutants: NO_x, SO_2, PM_{10}, and H_2SO_4. It is not subject to PSD review for other regulated air pollutants because the emissions of these pollutants will be less than the FDEP thresholds which trigger PSD review.

The BACT analysis for the project considered all of the pollutants subject to PSD, as indicated above. The analysis examined the environmental, energy, and economic considerations for those pollution control strategies determined to be technically feasible. In accordance with FDEP guidance, a "top-down" approach was utilized whereby the maximum degree of control required for a similar source in the U.S. was determined by reviewing EPA BACT Clearinghouse and California BACT Clearinghouse information. The most stringent emission limitations would be considered as BACT for this project unless the emission limitation is either technically infeasible or of unreasonable cost when considering environmental, energy, and economic factors.

In the case of NO_x control, two options were examined: (1) Selective Catalytic Reduction (SCR) technology using special high temperature zeolite catalysts (this was considered to be potentially technically feasible), and (2) dry low NO_x combustion technology for natural gas firing conditions and water injection during distillate fuel oil firing. The analysis indicated that the SCR option is unreasonably expensive. BACT for NO_x was determined to be dry low NO_x combustion technology for natural gas firing and water injection during distillate fuel oil firing.

For SO_2 and H_2SO_4 control, BACT was determined to be fuel quality specification and a limitation on the hours of operation on distillate fuel oil. The sulfur content in natural gas is minimal and meets BACT. For distillate fuel oil, BACT was determined to be the low sulfur (0.05 percent by weight) distillate fuel required by the Clean Air Act Amendments of 1990 as a transportation fuel. GRU will restrict future purchases of distillate fuel oil at this facility to this sulfur content but requests FDEP permission to fire the existing on-site supply of distillate, which has a sulfur content of 0.25 percent, until that supply is drawn down.

For PM_{10} control, the analysis determined that BACT is a combination of combustion air filtration, good combustion practices, use of clean burning natural gas, and a limitation on hours of fuel oil firing.

With respect to the other review requirements, the proposed stack height of 52.0 feet was found to be within the GEP stack height requirements. The applicable NSPS was determined to be 40 CFR 60 Subpart GG, and the proposed CT will comply with its requirements. Finally, the only additional state emission limits which apply to the proposed CT are a 20 percent opacity visible emissions limit and a prohibition on objectionable odors. The project will comply with these state restrictions.

The existing air quality in the site area was evaluated through the use of data from existing monitoring sites. Monitoring is not required by FDEP in cases where a proposed source will have ambient impacts below certain de minimis concentrations. GRU demonstrated that the impacts from the proposed CT will be below these levels and FDEP granted GRU's monitoring exemption request. Background air quality monitoring data from Gainesville, Palatka, and Jacksonville indicated that existing ambient concentrations are low and well within the allowable AAQS.

The modelling protocol for and receptor point grids used in the air quality impacts analysis were approved by FDEP. The ISCST2 dispersion model was the primary model used to analyze the impacts of the proposed CT. The analysis used five years of meteorological data from Gainesville (surface) and Tampa (upper air) which was supplied by FDEP. The emissions data used in the modelling represented "worst-case" conditions based on a range of fuels, operating scenarios, and ambient conditions. Downwash from the stack was evaluated in accordance with FDEP modelling guidelines.

Air quality screening modelling identified various combinations of CT load, ambient temperature, and fuel which produced "worst-case" ground-level concentrations for the different pollutants and averaging times. These worst-case combinations were modelled in more detail to determine if there would be any significant (as defined in Ch. 17-212.200(63) F.A.C.) off-site impacts. The modelling confirmed that there will be no significant off-site impacts due to the proposed CT and that additional modelling of existing sources in combination with the proposed CT was not necessary. Maximum off-site impacts due to the proposed CT were compared with Florida and National AAQS and the applicable Class II PSD increments. These were found to be well within the allowable limits.

The potential impacts of the proposed CT on the nearest Class I PSD areas were evaluated in accordance with procedures approved by FDEP and compared with the National Park Service significance criteria. The modelling results indicated that the project will not have a significant impact on the Class I areas.

An analysis of hazardous air pollutants was conducted based on FDEP guidelines. Using conservative, worst-case assumptions for emission rates and meteorological conditions the potential ambient impacts of twelve (12) hazardous air pollutants, primarily metals contained in distillate fuel oil, were evaluated. The maximum predicted impacts were below FDEP's draft No Threat Levels, and therefore no further analysis was necessary.

An additional impacts analysis conducted in accordance with the PSD requirements determined that project-related growth will not significantly affect air quality or visibility, soils and vegetation in the Class I areas.

The proposed project will apply BACT to control its emissions, will meet other state emission requirements, will comply with AAQS and PSD increment requirements, will not cause exceedances of FDEP's draft No Threat Levels, and will not cause any other significant air quality problems. Therefore, reasonable assurances have been provided to support FDEP's issuance of a PSD permit for the project.

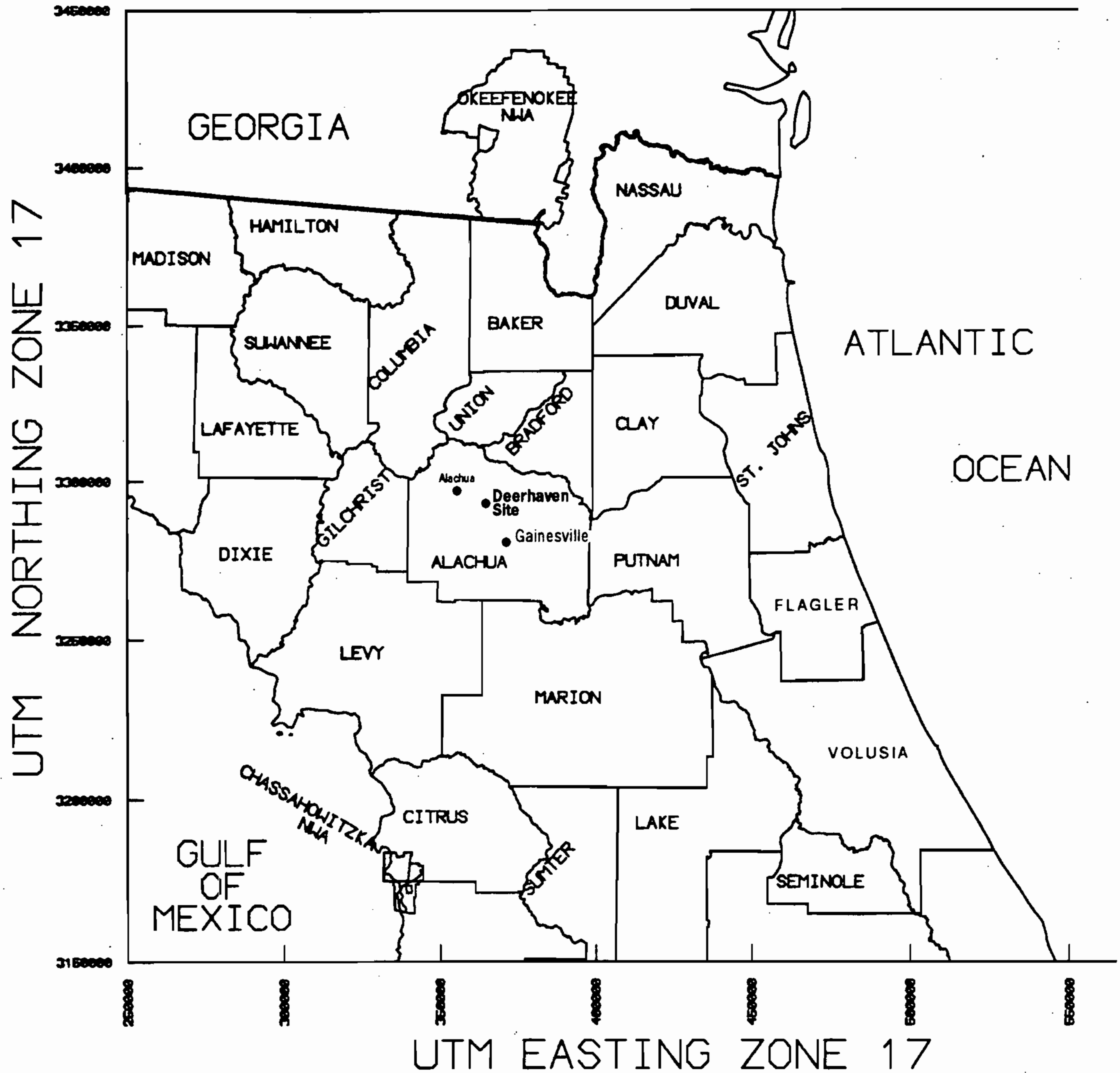
1.0 INTRODUCTION

Gainesville Regional Utilities (GRU) is planning to install a 74 MW (nominal), dual fuel, simple cycle combustion turbine (CT) at its Deerhaven Generating Station site approximately seven miles north of Gainesville, in Alachua County. The project is designed to allow its integration into existing facilities. Ebasco Services Incorporated has been contracted to engineer and construct the CT and ENSERCH Environmental (formerly the Environmental Division of Ebasco Services Incorporated) has been contracted to assist GRU with the environmental permitting. Figure 1-1 presents a general location map of the area and Figure 1-2 is a site location map. Figure 1-3 presents the existing Deerhaven site layout with the location of the proposed CT identified.

The existing Deerhaven Generating Station consists of two steam generating units (a nominal 81 MW gas/oil-fired unit (Unit 1) and a nominal 235 MW coal-fired unit (Unit 2)), and two nominal 22 MW gas/oil fired combustion turbines, designated DHCT1 and DHCT2. The coal-fired unit was licensed through the Florida Power Plant Siting Act (PPSA) process (GRU, 1977). Thus, the Deerhaven Generating Station is a "certified site" under the PPSA's jurisdiction. The addition of the new gas/oil fired combustion turbine is being treated as a modification of the 1978 site certification. This Prevention of Significant Deterioration (PSD) application is being submitted in conjunction with the modification request rather than as a separate federal application because the Florida Department of Environmental Protection (FDEP) has been authorized to issue PSD permits for projects covered by the Power Plant Siting Act.

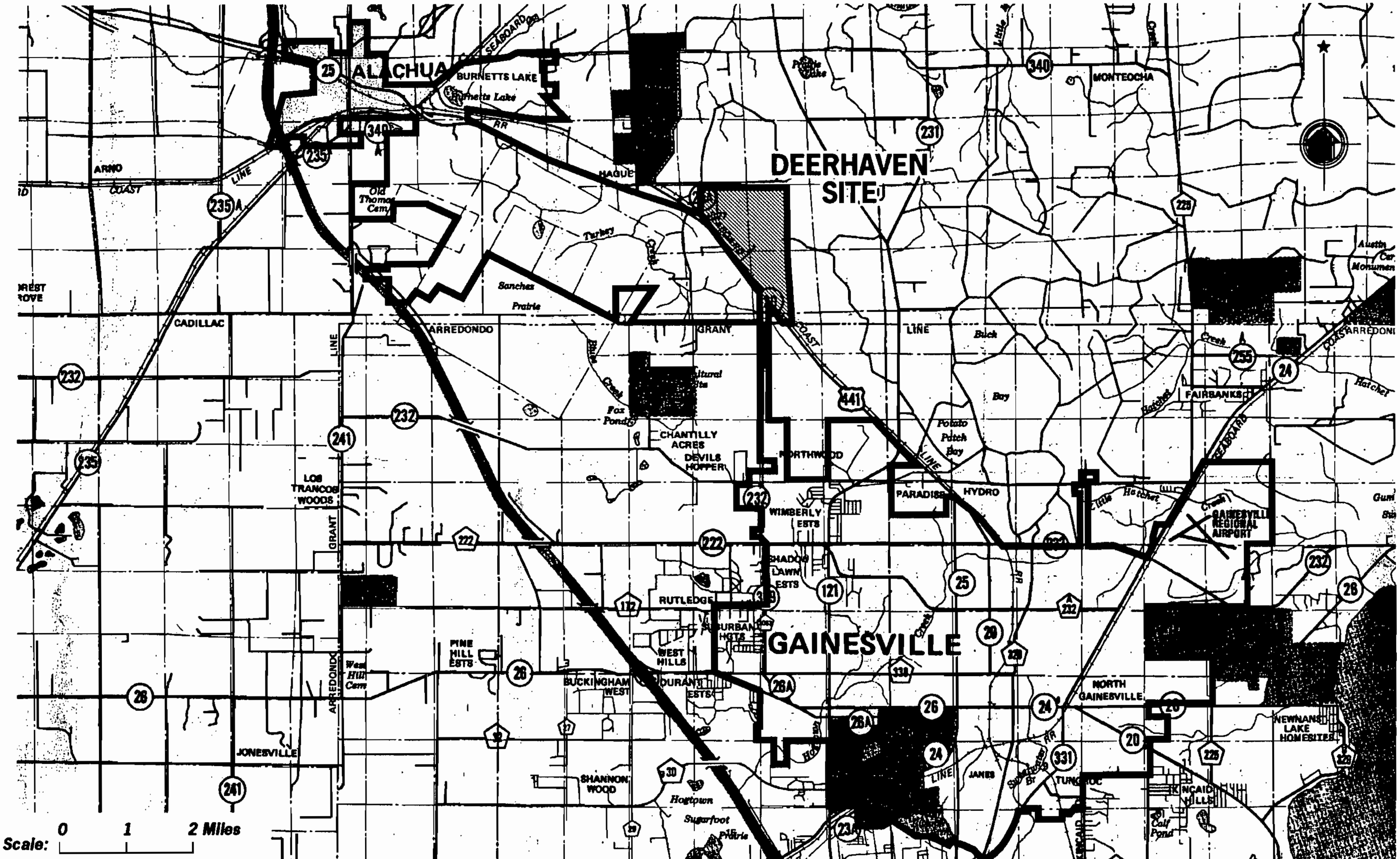
The U.S. Environmental Protection Agency (EPA) has promulgated Prevention of Significant Deterioration (PSD) regulations (40 CFR 52.21), which require a permit review and approval for new or modified existing sources that increase air pollutant emissions above specified threshold levels. These emission threshold levels will be exceeded by the project. As a result, the project is subject to PSD review. The federal PSD regulations are implemented by FDEP through EPA approval of Florida's PSD program. FDEP's PSD regulations are codified in the Florida Administrative Code (F.A.C.) Ch.17-212.400. The FDEP Application to Operate/Construct Air Pollution Sources for the project is attached to the front of this document.

The technical information and analysis required by the federal and state PSD regulations is contained in this PSD permit application. Although this document is associated with a Request for Modification of Site Certification (PA74-04) to incorporate the proposed facility,



Source: ENSERCH Environmental, 1994

GRU	**REGIONAL LOCATION MAP** **Alachua County, Florida**	**FIGURE** **1-1**

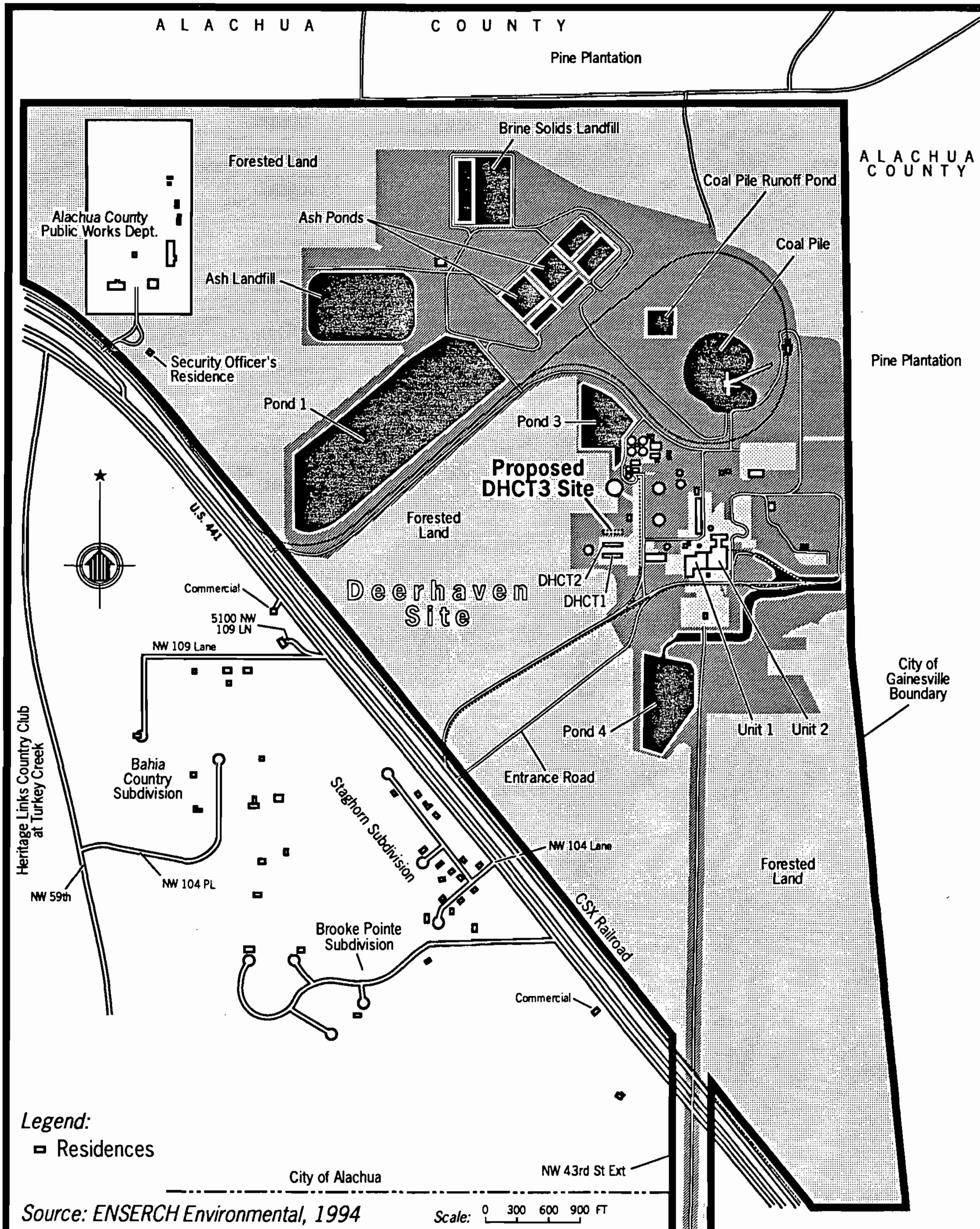


Source: ENSERCH Environmental, 1994 and Dolph Map Co., 1991

GRU

DEERHAVEN SITE LOCATION
Alachua County, Florida

FIGURE
1-2



GRU

DEERHAVEN SITE PLAN

FIGURE 1-3

it has been prepared as a stand-alone PSD permit application. The permit application is divided into eight major sections. Presented in Section 2.0 is a description of the project including the new CT's air pollutant emissions and stack parameters. Air quality review requirements and applicability are presented in Section 3.0. The best available control technology (BACT) analysis is presented in Section 4.0. An ambient air quality monitoring data analysis is presented in Section 5.0, and the air quality modelling methodology, the results of the air quality impact assessment, and additional air quality analyses performed for the proposed project are presented in Sections 6.0, 7.0, and 8.0, respectively. A brief conclusion is presented in Section 9.0. Section 10.0 contains a list of references and materials cited. Copies of the emissions source material and calculations are included as Appendices. Completed application forms are attached at the front of this document.

2.0 PROJECT DESCRIPTION

2.1 GENERAL DESCRIPTION

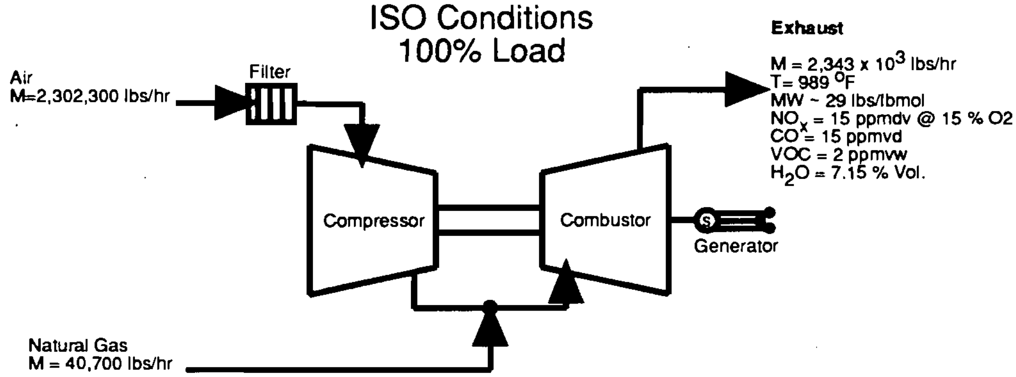
The proposed project will consist of the construction of a new simple cycle combustion turbine (CT) at the existing Deerhaven Generating Station. It will be designated as DHCT3. The new CT will provide a nominal 74 MW of additional generating capacity to the site. The CT will fire natural gas as the primary fuel, with low sulfur fuel oil as backup and will function as an intermediate peaking unit, operating no more than 3,900 hours per year. The CT selected is a General Electric (GE) Model MS7001EA dry low NO_x unit. It will be capable of operating in any of three modes: natural gas firing (NGF), natural gas firing with power augmentation (NGFPA) or distillate fuel oil firing (FOF). A simplified flow diagram for International Standards Organization (ISO) conditions (59°F, 60% relative humidity, sea level pressure) is provided in Figure 2-1.

NGFPA operation (which will be limited to a maximum of 390 hours per year) is accomplished by introducing water into the CT combustors slightly downstream of the flame. During this time, the combustion mode is more like that of a conventional combustor with the water serving to help reduce emissions. This is not as effective control as with the dry low NO_x combustors in the pre-mix mode (NGF). Since the CT is a mass flow device, the addition of the water increases the output by about eight percent (8%) over the normal maximum power output. This type of operation will be limited to those times when the system demand is higher than the capacity available from existing on-line generation.

During NGF operations, oxides of nitrogen (NO_x) emissions will be controlled through the use of staged combustion with GE dry low NO_x combustors. During FOF operation (which will be limited to a maximum of 2,000 hours per year), NO_x emissions will be controlled by use of water injection to reduce peak flame temperature. Sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) emissions will be controlled through the use of natural gas and by limiting the use of low sulfur fuel oil to no more than 2,000 hours per year. Carbon monoxide (CO), volatile organic compounds (VOCs) and particulate matter (PM) emissions will be controlled through good combustion practices. PM emissions will be further reduced by filtering the combustion air. Trace metal emissions (i.e., lead (Pb), beryllium (Be), arsenic (As), mercury (Hg)) will result in ambient impacts below the FDEP's draft "No Threat Levels" and applicable ambient standards.

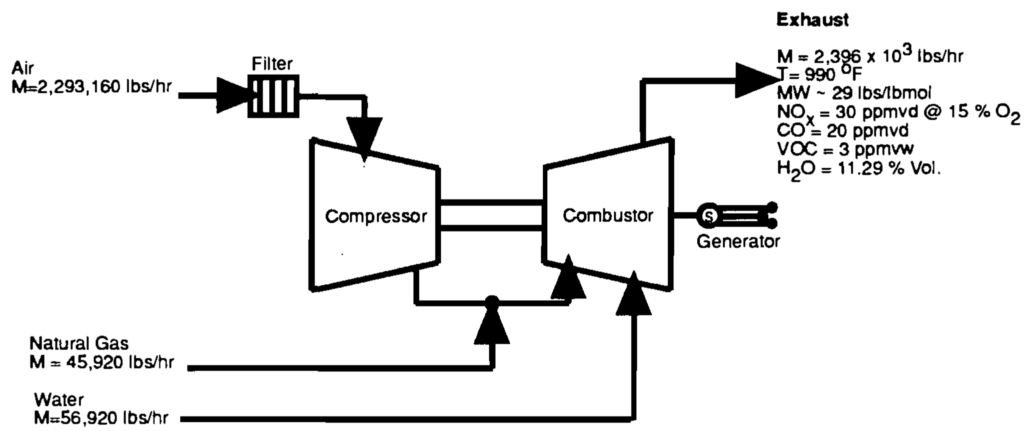
Natural Gas Firing - Dry Low NO_X Combustors

ISO Conditions
100% Load



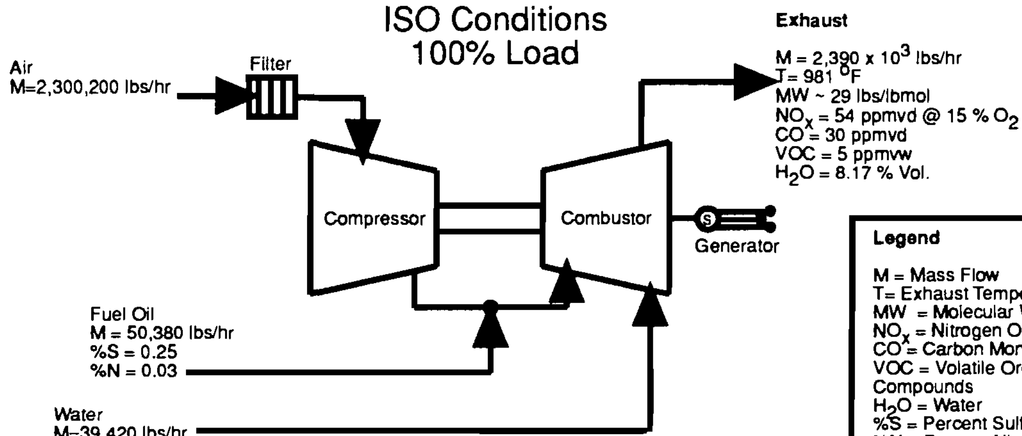
Natural Gas Firing with Power Augmentation - Water Injection

ISO Conditions
100% Load



Fuel Oil Firing - Water Injection

ISO Conditions
100% Load



Legend

M = Mass Flow
T= Exhaust Temperature
MW = Molecular Weight
NO_x = Nitrogen Oxides
CO = Carbon Monoxide
VOC = Volatile Organic Compounds
H_2O = Water
%S = Percent Sulfur
%N = Percent Nitrogen

GRU

SIMPLIFIED PROCESS FLOW DIAGRAM

Figure 2-1

2.2 PROPOSED SOURCE EMISSIONS AND STACK PARAMETERS

The estimated stack emissions and exhaust parameters that are representative of the advanced CT design (General Electric, 1993) proposed for the project are presented in Tables 2-1 through 2-7 for the nominal 74 MW CT unit. These tables present the natural gas and fuel oil cases for four ambient temperatures: 20°F, 59°F, 75°F and 95°F. GE data sheets which form the basis for these tables are contained in Appendix A. These tables include both regulated criteria air pollutants (NO_2, CO, SO_2, PM_{10}, VOC and Pb) and regulated noncriteria air pollutants. Although a number of these pollutants (primarily the hazardous air pollutants) are no longer subject to PSD review according to EPA's Clean Air Act Transition Guidance (EPA, 1991), it is understood that FDEP will continue to review impacts of those pollutants listed under Title III of the 1990 Clean Air Act Amendments during the PSD review process.

Worst-case air quality impacts due to the proposed facility are a function of emission rate and plume rise. Emission rates and plume rise from all fossil fuel fired power plants are functions of plant load. However, unlike conventional steam generating units, the fuel consumption, emission rates, and plume rise from CTs are also functions of ambient temperature. Although it is not practical to model all possible operating scenarios for the facility, a large number of cases (combinations of operating conditions and fuel types) were examined to represent the range of conditions that will occur during actual operations. The low (20°F) and high (95°F) ambient temperatures are reasonable extreme points selected to indicate the influence of compressor inlet temperature on combustion turbine performance and emissions/exhaust characteristics. It should be recognized, however, that the CT may operate at temperatures outside this range for short periods of time during a given year. The 75°F temperature case represents annual average temperature conditions for the Deerhaven Generating Station, and the 59°F temperature case represents the ISO conditions case. The 60 percent, 80 percent, and 100 percent loads represent the range of loads over which the CT is likely to be operated on both fuels.

A review of the CT design information in Tables 2-1 through 2-7 indicates that highest criteria air pollutant emission rates occur when burning distillate fuel oil. Combustion of natural gas and distillate fuel oil result in similar exhaust gas flow rates and stack exit temperatures, which are directly related to plume rise.

Natural gas is supplied to the site by Florida Gas Transmission. Number 2 (distillate) fuel oil is obtained from various suppliers and is stored in an on-site tank. An existing supply of 387,000 gallons of fuel oil with a sulfur content of 0.25 percent (by weight) is stored in a

TABLE 2-1
SIMPLE CYCLE UNIT
ESTIMATED [1] PERFORMANCE ON NATURAL GAS (100% LOAD)

<u>CONDITIONS</u>				
Ambient Temperature (°F)	20	75	95	ISO (59)
Ambient Relative Humidity (%)	100	90	50	ISO (60)
Elevation (ft) (above MSL)	178	178	178	ISO (0)
Maximum Heat Input Rate (mmBtu/hr)[2]	1,074.5	931.1	868.3	971.1
<u>EMISSIONS</u> (lb/hr)				
Carbon Monoxide	35	31	29	32
Nitrogen Oxides (at 15% O_2) (15 ppmvd)	58	51	47	53
Sulfur Dioxide[3]	29	25	24	26
Particulate Matter (PM_{10})	7	7	7	7
Volatile Organic Compounds (non-methane HC)	3	2.7	2.6	2.8
Lead	Neg.	Neg.	Neg.	Neg.
Asbestos	Neg.	Neg.	Neg.	Neg.
Beryllium	Neg.	Neg.	Neg.	Neg.
Mercury	Neg.	Neg.	Neg.	Neg.
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.
Total Fluorides	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist	3.0	2.6	2.5	2.8
Hydrogen Sulfide	Neg.	Neg.	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.
Benzene	Neg.	Neg.	Neg.	Neg.
Inorganic Arsenic	Neg.	Neg.	Neg.	Neg.
Radionuclides	Neg.	Neg.	Neg.	Neg.
<u>STACK PARAMETERS</u>				
Stack Height (ft)	52	52	52	52
Stack Diameter (ft)	14.1	14.1	14.1	14.1
Stack Gas Temperature (°F)	964	1001	1011	989
Stack Gas Exit Velocity (ft/sec)	160	144	138	149

(1) Emission estimates based on manufacturer's data (GE, 1993).
(2) For CT's the heat input rate is based on the higher heating value of the fuel.
(3) Sulfur dioxide emissions based on 10 grains/100 SCF total sulfur in natural gas.

MSL = Mean sea level
Neg. = Negligible

Source: ENSERCH Environmental, 1994

TABLE 2-2
SIMPLE CYCLE UNIT
ESTIMATED [1] PERFORMANCE ON NATURAL GAS (80% LOAD)

CONDITIONS				
Ambient Temperature (°F)	20	75	95	ISO (59)
Ambient Relative Humidity (%)	100	90	50	ISO (60)
Elevation (ft) (above MSL)	178	178	178	ISO (0)
Maximum Heat Input Rate (mmBtu/hr)[2]	896	792.9	758.8	821.5
EMISSIONS (lb/hr)				
Carbon Monoxide	29	26	24	27
Nitrogen Oxides (at 15% O_2) (15 ppmvd)	49	43	41	44
Sulfur Dioxide[3]	25	21	21	22
Particulate Matter (PM_{10})	7	7	7	7
Volatile Organic Compounds (non-methane HC)	3	2.7	2.6	2.8
Lead	Neg.	Neg.	Neg.	Neg.
Asbestos	Neg.	Neg.	Neg.	Neg.
Beryllium	Neg.	Neg.	Neg.	Neg.
Mercury	Neg.	Neg.	Neg.	Neg.
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.
Total Fluorides	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist	2.5	2.25	2.15	2.33
Hydrogen Sulfide	Neg.	Neg.	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.
Benzene	Neg.	Neg.	Neg.	Neg.
Inorganic Arsenic	Neg.	Neg.	Neg.	Neg.
Radionuclides	Neg.	Neg.	Neg.	Neg.
STACK PARAMETERS				
Stack Height (ft)	52	52	52	52
Stack Diameter (ft)	14.1	14.1	14.1	14.1
Stack Gas Temperature (°F)	988	1037	1058	1022
Stack Gas Exit Velocity (ft/sec)	133	123	120	126

(1) Emission estimates based on manufacturer's data (GE, 1993).
(2) For CT's the heat input rate is based on the higher heating value of the fuel.
(3) Sulfur dioxide emissions based on 10 grains/100 SCF total sulfur in natural gas.

MSL = Mean sea level
Neg. = Negligible

Source: ENSERCH Environmental, 1994

TABLE 2-3
SIMPLE CYCLE UNIT
ESTIMATED [1] PERFORMANCE ON NATURAL GAS (60% LOAD)

CONDITIONS				
Ambient Temperature (°F)	20	75	95	ISO (59)
Ambient Relative Humidity (%)	100	90	50	ISO (60)
Elevation (ft) (above MSL)	178	178	178	ISO (0)
Maximum Heat Input Rate (mmBtu/hr)[2]	760	678.1	649	701.9
EMISSIONS (lb/hr)				
Carbon Monoxide	24	21	35	23
Nitrogen Oxides (at 15% O_2) (15 ppmvd)	41	37	35	38
Sulfur Dioxide[3]	21	18	18	19
Particulate Matter (PM_{10})	7	7	7	7
Volatile Organic Compounds (non-methane HC)	3	2.7	2.6	2.8
Lead	Neg.	Neg.	Neg.	Neg.
Asbestos	Neg.	Neg.	Neg.	Neg.
Beryllium	Neg.	Neg.	Neg.	Neg.
Mercury	Neg.	Neg.	Neg.	Neg.
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.
Total Fluorides	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist	2.2	1.9	1.8	2.0
Hydrogen Sulfide	Neg.	Neg.	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.
Benzene	Neg.	Neg.	Neg.	Neg.
Inorganic Arsenic	Neg.	Neg.	Neg.	Neg.
Radionuclides	Neg.	Neg.	Neg.	Neg.
STACK PARAMETERS				
Stack Height (ft)	52	52	52	52
Stack Diameter (ft)	14.1	14.1	14.1	14.1
Stack Gas Temperature (°F)	1037	1086	1100	1072
Stack Gas Exit Velocity (ft/sec)	104	107	105	118

[1] Emission estimates based on manufacturer's data (GE, 1993).
[2] For CT's the heat input rate is based on the higher heating value of the fuel.
[3] Sulfur dioxide emissions based on 10 grains/100 SCF total sulfur in natural gas.

MSL = Mean sea level
Neg. = Negligible

Source: ENSERCH Environmental, 1994

TABLE 2-4
SIMPLE CYCLE UNIT
ESTIMATED [1] PERFORMANCE ON NATURAL GAS (100% LOAD)
POWER AUGMENTATION MODE

CONDITIONS		
Ambient Temperature (°F)	95	ISO (59)
Ambient Relative Humidity (%)	50	ISO (60)
Elevation (ft) (above MSL)	178	ISO (0)
Maximum Heat Input Rate (mmBtu/hr)[2]	986.1	1096.6
EMISSIONS (lb/hr)		
Carbon Monoxide	38	42
Nitrogen Oxides (at 15% O_2) (30 ppmvd)	107	120
Sulfur Dioxide[3]	27	30
Particulate Matter (PM_{10})	7	7
Volatile Organic Compounds (non-methane HC)	4	4.5
Lead	Neg.	Neg.
Asbestos	Neg.	Neg.
Beryllium	Neg.	Neg.
Mercury	Neg.	Neg.
Vinyl Chloride	Neg.	Neg.
Total Fluorides	Neg.	Neg.
Sulfuric Acid Mist	2.8	3.1
Hydrogen Sulfide	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.
Benzene	Neg.	Neg.
Inorganic Arsenic	Neg.	Neg.
Radionuclides	Neg.	Neg.
STACK PARAMETERS		
Stack Height (ft)	52	52
Stack Diameter (ft)	14.1	14.1
Stack Gas Temperature (°F)	1014	990
Stack Gas Exit Velocity (ft/sec)	142	153

(1) Emission estimates based on manufacturer's data (GE, 1993).
(2) For CT's the heat input rate is based on the higher heating value of the fuel.
(3) Sulfur dioxide emissions based on 10 grains/100 SCF total sulfur in natural gas.

MSL = Mean sea level
Neg. = Negligible

Source: ENSERCH Environmental, 1994

TABLE 2-5
SIMPLE CYCLE UNIT
ESTIMATED [1] PERFORMANCE ON FUEL OIL (100% LOAD)

<u>CONDITIONS</u>				
Ambient Temperature (°F)	20	75	95	ISO (59)
Ambient Relative Humidity (%)	100	90	50	ISO (60)
Elevation (ft) (above MSL)	178	178	178	ISO (0)
Maximum Heat Input Rate (mmBtu/hr)[2]	1,100	938.6	883.7	990.6
<u>EMISSIONS</u> (lb/hr)				
Carbon Monoxide	71	62	59	65
Nitrogen Oxides (at 15% O_2) (54 ppmvd)[3]	237	201	189	213
Sulfur Dioxide[4]	266	227	214	240
Sulfur Dioxide[5]	53	45	43	48
Particulate Matter (PM_{10})	15	15	15	15
Volatile Organic Compounds	7	6	6	6
Lead [6]	0.06380	0.05444	0.05126	0.05746
Asbestos	Neg.	Neg.	Neg.	Neg.
Beryllium [6]	0.00036	0.00031	0.00029	0.00032
Mercury [6]	0.0010	0.00085	0.0008	0.0009
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.
Total Fluorides	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist[4]	28	24	22	25
Sulfuric Acid Mist[5]	5.6	4.8	4.5	5.0
Hydrogen Sulfide	Neg.	Neg.	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.
Benzene	Neg.	Neg.	Neg.	Neg.
Inorganic Arsenic	0.00539	0.004599	0.00433	0.004854
Radionuclides	Neg.	Neg.	Neg.	Neg.
<u>STACK PARAMETERS</u>				
Stack Height (ft)	52	52	52	52
Stack Diameter (ft)	14.1	14.1	14.1	14
Stack Gas Temperature (°F)	955	994	1007	981
Stack Gas Exit Velocity (ft/sec)	162	146	141	152

(1) Emission estimates based on manufacturer's data (GE, 1993).
(2) For CT's the heat input rate is based on the higher heating value of the fuel.
(3) Maximum FBN content = 0.03% = an additional 12ppmvd NO_x above 42 ppmvd.
(4) Sulfur dioxide and sulfuric acid mist based on 0.25% sulfur by weight in the fuel (current fuel oil supply).
(5) Sulfur dioxide and sulfuric acid mist based on 0.05% sulfur by weight in fuel (future fuel oil supply)
(6) Emission estimates from U.S. EPA (1993).

MSL = Mean sea level
Neg. = Negligible

Source: ENSERCH Environmental, 1994

TABLE 2-6
SIMPLE CYCLE UNIT
ESTIMATED [(1)] PERFORMANCE ON FUEL OIL (80% LOAD)

<u>CONDITIONS</u>				
Ambient Temperature (°F)	20	75	95	ISO (59)
Ambient Relative Humidity (%)	100	90	50	ISO (60)
Elevation (ft) (above MSL)	178	178	178	ISO (0)
Maximum Heat Input Rate (mmBtu/hr)[(2)]	926	798	755.7	840
<u>EMISSIONS</u> (lb/hr)				
Carbon Monoxide	56	50	48	53
Nitrogen Oxides (at 15% O_2) (54 ppmvd)[(3)]	197	170	161	179
Sulfur Dioxide[(4)]	224	193	183	203
Sulfur Dioxide[(5)]	45	39	37	41
Particulate Matter (PM_{10})	15	15	15	15
Volatile Organic Compounds	6	5	6	6
Lead [(6)]	0.05371	0.04628	0.043832	0.04872
Asbestos	Neg.	Neg.	Neg.	Neg.
Beryllium [(6)]	0.00031	0.00026	0.00025	0.00030
Mercury [(6)]	0.00084	0.00073	0.00069	0.00076
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.
Total Fluorides	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist[(4)]	23	20	19	21
Sulfuric Acid Mist[(5)]	4.7	4.0	3.8	4.3
Hydrogen Sulfide	Neg.	Neg.	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.
Benzene	Neg.	Neg.	Neg.	Neg.
Inorganic Arsenic	0.004537	0.00391	0.003703	0.004116
Radionuclides	Neg.	Neg.	Neg.	Neg.
<u>STACK PARAMETERS</u>				
Stack Height (ft)	52	52	52	52
Stack Diameter (ft)	14.1	14.1	14.1	14.1
Stack Gas Temperature (°F)	1001	1050	1058	1042
Stack Gas Exit Velocity (ft/sec)	132	124	120	127

(1) Emission estimates based on manufacturer's data (GE, 1993).
(2) For CT's the heat input rate is based on the higher heating value of the fuel.
(3) Maximum FBN content = 0.03% = an additional 12ppmvd NO_x above 42 ppmvd.
(4) Sulfur dioxide and sulfuric acid mist based on 0.25% sulfur by weight in the fuel (current fuel oil supply).
(5) Sulfur dioxide and sulfuric acid mist based on 0.05% sulfur by weight in fuel (future fuel oil supply)
(6) Emission estimates from U.S. EPA (1993).

MSL = Mean sea level
Neg. = Negligible

Source: ENSERCH Environmental, 1994

TABLE 2-7

SIMPLE CYCLE UNIT

ESTIMATED [1] PERFORMANCE ON FUEL OIL (60% LOAD)

<u>CONDITIONS</u>				
Ambient Temperature (°F)	20	75	95	ISO (59)
Ambient Relative Humidity (%)	100	90	50	ISO (60)
Elevation (ft) (above MSL)	178	178	178	ISO (0)
Maximum Heat Input Rate (mmBtu/hr)[2]	782.9	680	646.1	714
<u>EMISSIONS</u> (lb/hr)				
Carbon Monoxide (40 ppm)	63	58	56	60
Nitrogen Oxides (at 15% O_2) (54 ppmvd)[3]	166	144	137	151
Sulfur Dioxide[4]	189	164	156	173
Sulfur Dioxide[5]	38	33	31	35
Particulate Matter (PM_{10})	15	15	15	15
Volatile Organic Compounds	5	5	9	9
Lead [6]	0.04541	0.03944	0.03747	0.04141
Asbestos	Neg.	Neg.	Neg.	Neg.
Beryllium [6]	0.00026	0.00022	0.00021	0.00024
Mercury [6]	0.00071	0.00062	0.00059	0.00065
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.
Total Fluorides	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist[4]	20	17	16	18
Sulfuric Acid Mist[5]	4.0	3.4	3.3	3.6
Hydrogen Sulfide	Neg.	Neg.	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.
Benzene	Neg.	Neg.	NEg.	Neg.
Inorganic	0.003836	0.003332	0.003166	0.003499
Radionuclides	Neg.	Neg.	Neg.	Neg.
<u>STACK PARAMETERS</u>				
Stack Height (ft)	52	52	52	52
Stack Diameter (ft)	14.1	14.1	14.1	14.1
Stack Gas Temperature (°F)	1068	1086	1092	1080
Stack Gas Exit Velocity (ft/sec)	162	146	141	111

(1) Emission estimates based on manufacturer's data (GE, 1993).
(2) For CT's the heat input rate is based on the higher heating value of the fuel.
(3) Maximum FBN content = 0.03% = an additional 12ppmvd NO_x above 42 ppmvd.
(4) Sulfur dioxide and sulfuric acid mist based on 0.25% sulfur by weight in the fuel (current fuel oil supply).
(5) Sulfur dioxide and sulfuric acid mist based on 0.05% sulfur by weight in fuel (future fuel oil supply)
(6) Emission estimates from U.S. EPA (1993).

MSL = Mean sea level
Neg. = Negligible

Source: ENSERCH Environmental, 1994

tank near the proposed CT and is used for light-off oil for the two steam units and as the secondary fuel for DHCT1 and DHCT2. Future distillate fuel oil purchases for the Deerhaven Site will be of the very low sulfur (0.05%) type required by the Clean Air Act Amendments of 1990 for transportation fuel. A limit of .03% fuel bound nitrogen (FBN) was requested after talking with various fuel oil suppliers and finding the range to be .01% to over .03%. Most suppliers felt distillate fuel oil could be supplied with an FBN between .01 and .03%. GRU will make every effort to procure the lowest economical FBN levels in future distillate fuel oil purchases. Typical fuel analyses for natural gas and for low sulfur distillate fuel oil are presented in Tables 2-8 and 2-9, respectively.

TABLE 2-8
TYPICAL NATURAL GAS ANALYSIS

Analysis	Mole (%)
Carbon Dioxide	0.74
Ethane	2.7
Methane	95.8
Nitrogen	0.48
Propane	0.16
Other	0.12
Total:	100.00
Specific Gravity (air at 1)	0.71
Quality Information	**Parameters**
Heating Value (LHV)	21,175.8 Btu/lb
Total Sulfur (Maximum)	10 grains/100 SCF

Source: Ebasco, 1993

TABLE 2-9
TYPICAL FUEL OIL ANALYSIS

Distillate Oil	Weight (Percent)
Carbon	86
Hydrogen	12
Nitrogen	0.015[1]
Oxygen	1
Sulfur	0.035[1]
Ash	0.04

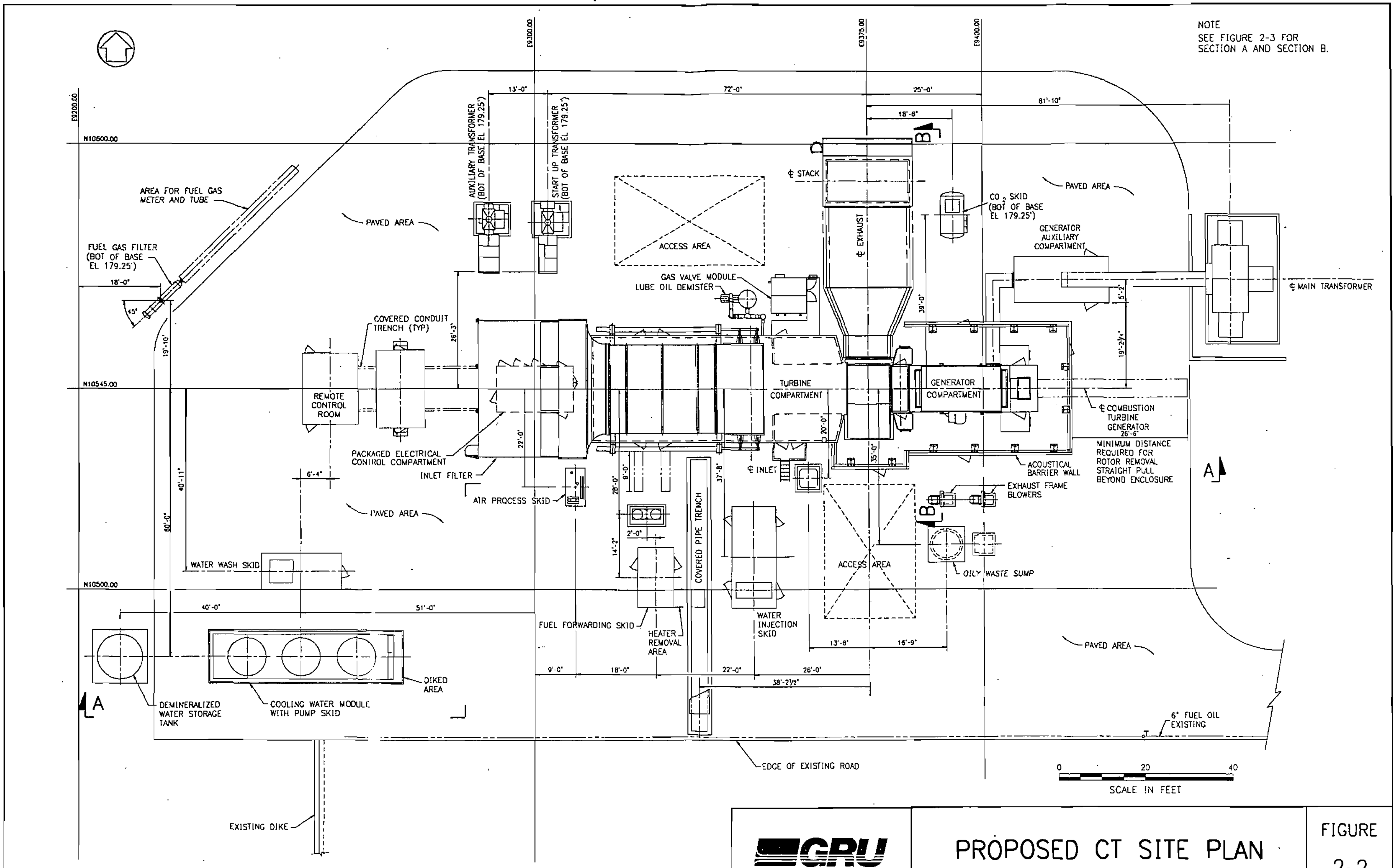
Lower Heating Value: 18,550 Btu/lb
Higher Heating Value: 19,200 Btu/lb

[1] GRU, 1994

Source: Ebasco, 1993

2.3 SITE LAYOUT AND STRUCTURES

Figure 2-2 contains the site plan depicting the proposed CT. Figure 2-3 depicts the profile of the proposed CT.



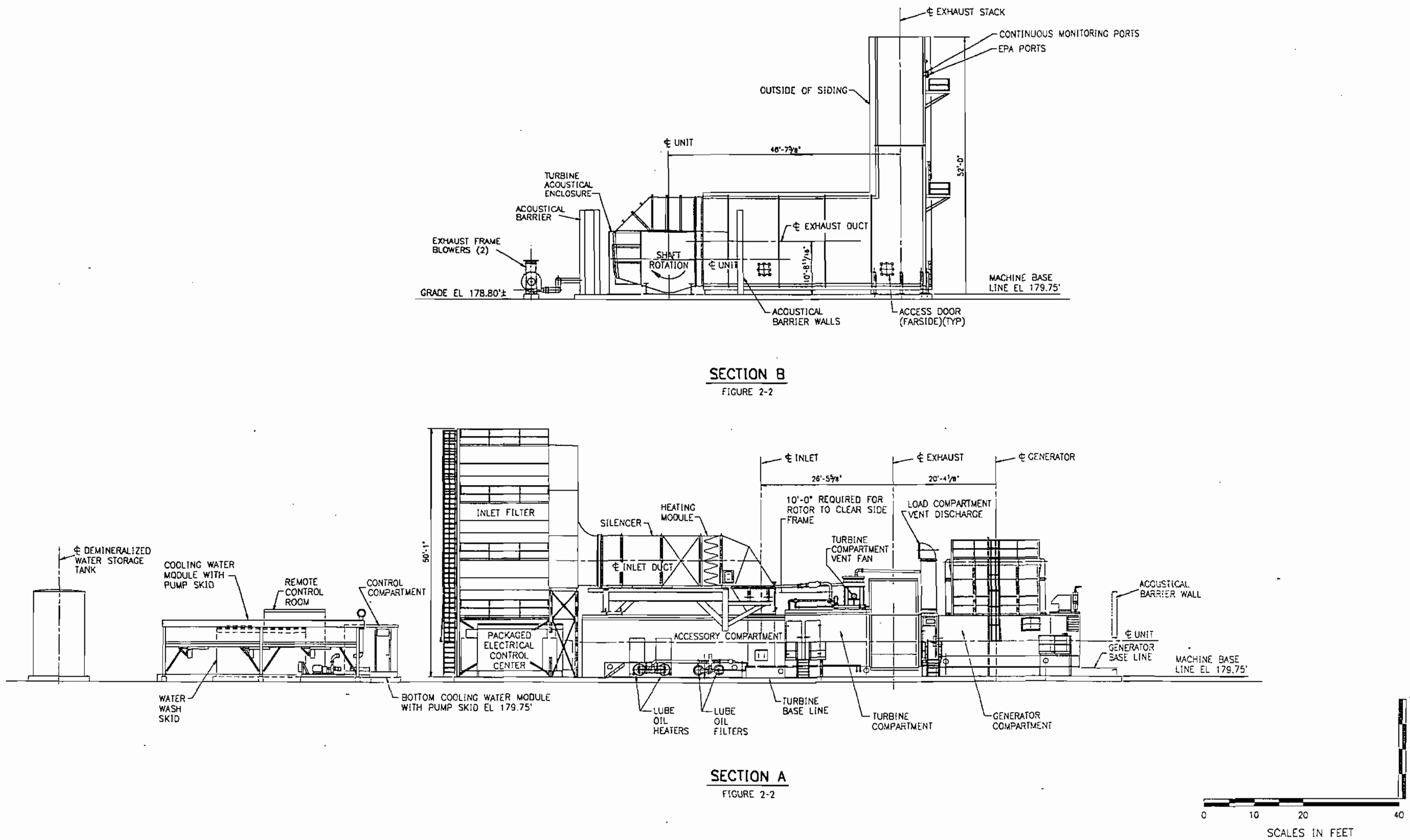
SOURCE: EBASCO SERVICES INCORPORATED, 1994

PLOT DATE FEBRUARY 25, 1994 FILENAME C:\GRU-4124\FIG-2-2.DWG

GRU

PROPOSED CT SITE PLAN

FIGURE 2-2



PLOT DATE FEBRUARY 25, 1994 FILENAME C:\GRU-4124\FIG-2-3.DWG

SOURCE: EBASCO SERVICES INCORPORATED, 1994

GRU

PROPOSED CT SITE PROFILE

FIGURE 2-3

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to the project. These regulations must be satisfied before the proposed facility can be constructed and begin operation.

3.1 NATIONAL AND FLORIDA AMBIENT AIR QUALITY STANDARDS (NAAQS/FAAQS)

The applicable federal (NAAQS) and state (FAAQS) ambient air quality standards are presented in Table 3-1 (PSD increments are also presented in Table 3-1, but discussed in Section 3.2.2). These ambient air quality standards have been promulgated for six pollutants, known as the "criteria" pollutants: NO_2, CO, SO_2, PM_{10}, VOC, and Pb. The primary NAAQS/FAAQS were promulgated to protect the public health, and the secondary NAAQS/FAAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Alachua County is an "attainment" area for all criteria pollutants, meaning that existing concentrations are within the allowable primary and secondary standards.

3.2 PSD REVIEW REQUIREMENTS

3.2.1 General Requirements

Under the federal and FDEP PSD permit review requirements, all major new or modified existing sources of air pollutants located in attainment areas and regulated under the Clean Air Act (CAA) must be reviewed and approved. A "major stationary source" is defined as any one of 28 specified source categories which has the potential to emit 100 tons per year (TPY) or more, or any other stationary source which has the potential to emit 250 TPY or more of any air pollutant regulated under the CAA. Fossil fuel-fired steam electric plants of more than 250 mmBtu/hr of heat input comprise one of the 28 specified source categories. Thus, the existing Deerhaven Generating Station's steam units are subject to the 100 TPY cutoff. The term "potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. The emissions from the existing units exceed the 100 TPY criteria. Therefore, the Deerhaven Generating Station is considered a major stationary source. Sources are considered major modifications if they will increase the potential to emit by more than the PSD significant emission rates listed in Table 3-2. The

TABLE 3-1
AMBIENT AIR QUALITY STANDARDS
AND PSD INCREMENTS

Pollutant	Averaging Time	Federal NAAQS ($\mu g/m^3$)	Florida FAAQS ($\mu g/m^3$)	Class I PSD Increment ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)
CO	1-hour	40,000	40,000	N/A	N/A
	8-hour	10,000	10,000	N/A	N/A
NO_2	Annual	100	100	2.5	25
SO_2	3-hour	1,300 (1)	1,300 (1)	25	512
	24-hour	365	260	5	91
	Annual	80	60	2	20
PM (2)	24-hour	150	150	10 (8)	37 (30)
	Annual	50	50	5 (4)	19 (17)
O_3 (3)	1-hour	235	235	N/A	N/A
Pb	Calendar Quarter	1.5	1.5	N/A	N/A

(1) The 3-hour average SO_2 ambient air quality standard is a secondary (welfare-related) standard. All of the other federal and Florida ambient air quality standards are primary (health-related) standards.

(2) Ambient air quality standards are based on PM_{10} and PSD increments are based on total suspended particulates (TSP) until June 3, 1994 when the PM_{10} PSD increment recently promulgated becomes effective. The new PSD increments will be 8 $\mu g/m^3$ (24-hr) and 4 $\mu g/m^3$ (annual) for Class I areas and 30 $\mu g/m^3$ (24-hr) and 17 $\mu g/m^3$ (annual) for Class II areas.

(3) Ozone values are associated with emissions of VOCs and NO_x.

Note: Short-term standards (i.e., those with averaging times less than annual) and increments can be exceeded once per year.

N/A = No PSD increments exist for these pollutants.
$\mu g/m^3$ = micrograms per cubic meter

Sources: 40 CFR 50; F.A.C. 17-272.300; F.A.C. 17-272.500; Federal Register Vol. 58 No. 105, June 3, 1993, p. 31,621 - 31,638.

TABLE 3-2
PSD SIGNIFICANT EMISSION RATES

Pollutant	Annual Significant Emission Rate (TPY)
Carbon Monoxide	100
Nitrogen Oxides	40
Sulfur Dioxide	40
Particulate Matter (PM_{10})	15
Total Suspended Particulates (TSP)	25
Volatile Organic Compounds	40
Lead	0.6
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl Chloride	1
Total Fluorides	3
Sulfuric Acid Mist	7
Reduced Sulfur Compounds (Including H_2S)	10
Total Reduced Sulfur (Including H_2S)	10

TPY = tons per year

Source: F.A.C. 17-212.400 Table 212.400-2 emissions from the proposed CT will exceed the PSD significant emission rates for some pollutants and thus subject the project to PSD review.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified source located in an attainment area. The PSD regulations are contained in Ch.17-212.400 F.A.C. Major sources and modifications are required to undergo the following analyses under PSD for each air pollutant emitted in significant quantities:

- A control technology analysis;
- An air quality impacts analysis; and
- An additional impacts analysis.

In addition to these analyses, a new source must also be reviewed with respect to Good Engineering Practice (GEP) stack height regulations (EPA, 1985a), New Source Performance Standards (NSPS), and any state emission standards.

3.2.2 PSD Increments/Classifications

In promulgating the 1977 Clean Air Act (CAA) Amendments, Public Law 95-95, Congress specified that certain increases above an air quality "baseline concentration" level for SO_2 and TSP concentrations would constitute "significant deterioration." The magnitudes of the allowable increases, or "increments," depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications were designated based on criteria established in the CAA Amendments of 1977. Initially, Congress designated PSD areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would allow greater deterioration than Class II areas, were designated. EPA subsequently incorporated the requirements for classifications and area designations into the PSD regulations.

On October 17, 1988, the EPA promulgated regulations to prevent significant deterioration due to NO_x emissions and established PSD increments for NO_2 concentrations. On June 3, 1993, EPA promulgated regulations which revised the PSD increments for particulate matter from TSP to PM_{10}. This change is to become effective on June 3, 1994. The allowable PSD increments for SO_2, TSP, PM_{10}, and NO_2 were presented in Table 3-1. The FDEP has adopted the EPA PSD classification scheme and the allowable PSD increments for SO_2, TSP, and NO_2. It is assumed that the EPA PSD increment for PM_{10} will be adopted by FDEP as well.

The term "baseline concentration" is derived from federal and state PSD regulations and denotes a concentration level corresponding to a specified baseline date and contributions from certain additional baseline sources. The PSD regulations (Ch. 17-212.200 F.A.C.) define baseline concentration as the ambient concentration level which is predicted to exist in the baseline area at the time of the applicable minor source baseline date. Emission increases after the baseline date consume PSD increments. A baseline concentration is determined for each pollutant for which PSD increments are promulgated and a baseline date is established. The baseline concentration includes:

1. The actual emissions representative of sources in existence on the applicable baseline date; and

2. The allowable emissions of major stationary sources which commenced construction before January 6, 1975, for SO_2 and TSP (now PM_{10}) concentrations, or before February 8, 1988, for NO_2 concentrations, but which were not in operation by the applicable baseline date.

3.2.3 Control Technology Review

The control technology review requirements of the PSD regulations require that all applicable federal and state emission limiting standards be met and that best available control technology (BACT) be applied to control emissions from the source. The BACT requirements apply to all applicable regulated and unregulated air pollutants for which the increase in emissions from the source or modification exceeds the PSD significant emission rates in Table 3-2.

BACT is defined in Ch. 17-212.200 F.A.C. as:

> An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the 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 (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.
>
> If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or

> facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.
>
> Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

The requirements for BACT were incorporated within the PSD framework in the 1977 CAA Amendments. The primary purpose of BACT is to minimize consumption of PSD increments and thereby increase the potential for future economic growth without significantly degrading air quality. Guidelines for the evaluation of BACT can be found in the draft *New Source Review Workshop Manual* (EPA, 1990a) and the draft *Top-Down BACT Guidance Document* (EPA, 1990c). These guidelines were issued by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. Although the "top-down" approach to BACT has been suspended by EPA as a result of a suit settlement until formal rulemaking is undertaken, FDEP is still requesting that this approach to BACT be used. BACT is determined on a case-by-case basis, and BACT for a source in one area may not be the same for an identical source located in another area. BACT analyses for the same types of emissions units and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors.

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, at a minimum, demonstrate compliance with the applicable New Source Performance Standards (NSPS). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A determination of BACT is to be based on sound judgement, balancing environmental benefits with energy, economic, and other impacts.

3.2.4 Ambient Air Quality Monitoring Requirements

In accordance with the requirements of Ch.17-212.400(5)(f) F.A.C., any application for a PSD permit must contain an analysis of continuous ambient air quality monitoring data in the area affected by the proposed major stationary source or major modification.

According to EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987), ambient air monitoring for a period of up to one year is generally appropriate to satisfy the PSD monitoring requirements. A minimum of four months of data are generally required. Existing data from the vicinity of the proposed source may be utilized if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered.

The PSD regulations include an exemption in Ch.17-212.400(3)(e) which states that the Department may exempt a proposed major stationary source or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the source or modification would cause, in any area, air quality impacts less than the *de minimis* air quality impact levels presented in Table 3-3.

3.2.5 Source Impact Analysis

A source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the PSD significant emission rate. The PSD regulations specifically require the use of atmospheric dispersion models in performing air quality impact analysis, estimating baseline and future air quality levels, and determining compliance with NAAQS/FAAQS and allowable PSD increments. Reference EPA models must normally be used in performing the impact analysis. Use of nonreference EPA models requires regulatory agency consultation and prior approval. Guidance for the regulatory application of dispersion models is presented in the U.S. EPA *Guideline on Air Quality Models (Revised)* (EPA, 1993a).

3.2.6 Additional Impacts Analysis

In addition to air quality impact analyses, the PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source. These analyses are to be conducted primarily for nearby PSD Class I

TABLE 3-3

PSD *DE MINIMIS* AMBIENT AIR QUALITY IMPACT LEVELS

Pollutant	Air Quality Impact *De Minimis* Level ($\mu g/m^3$) and Averaging Time [1]
Carbon Monoxide	575 (8-hour)
Nitrogen Dioxide	14 (Annual)
Sulfur Dioxide	13 (24-hour)
Particulate Matter (PM_{10})	10 (24-hour)
Particulate Matter (TSP)	10 (24-hour)
Volatile Organic Compounds (Ozone)	[2]
Lead	0.1 (3-month)
Beryllium	0.001 (24-hour)
Mercury	0.25 (24-hour)
Vinyl Chloride	15 (24-hour)
Total Fluorides	0.25 (24-hour)
Hydrogen Sulfide	0.2 (1-hour)

(1) Ambient air quality monitoring requirements for applicable pollutants may be exempted if the impact of the net increase in emissions is below the applicable air quality impact *de minimis* levels.

(2) No specific air quality impact *de minimis* level is prescribed for ozone. Exemptions are granted when a proposed source's VOC emissions are less than 100 tons/year.

Source: F.A.C. 17-212.400 Table 212.400-3 areas. Impacts on air quality due to general commercial, residential, industrial, and other growth related activities associated with the source must also be addressed. These analyses are required for each pollutant emitted in significant quantities.

3.3 OTHER REQUIREMENTS

In addition to the requirements of the PSD program, any new or modified source of air pollution must be reviewed with respect to the Good Engineering Practice (GEP) stack height regulations (Ch.17-210.550 F.A.C.), the federal NSPS requirements, and any state-specific emission standards.

3.3.1 Good Engineering Practice (GEP) Stack Height

The 1977 CAA Amendments require under Section 123 that the degree of emission limitation required for control of any air pollutant not be affected by a stack height that exceeds GEP, or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). FDEP has incorporated these rules into Ch.17-210.550 F.A.C.

The EPA's final stack height regulations define GEP stack height for stacks constructed after January 12, 1979, as the greater of:

(1) 65 meters, measured from the ground-level elevation at the base of the stack; or

(2) $H_g = H + 1.5\ L$

where:

H_g = GEP stack height, measured from the ground-level elevation at the base of the stack;

H = Height of nearby structure(s) measured from the ground-level elevation at the base of the stack; and

L = Lesser dimension, height or projected width of nearby structure(s).

The term "nearby" is defined by the GEP stack height regulations as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 km. Although GEP stack height regulations require that the stack height credit used in modelling for determining compliance with NAAQS/FAAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater. In this case the proposed stack for the 74 MW generating unit is 52.0 feet (15.8 meters) above ground level. GEP stack height as determined by the "GEP" program (Bowman, 1993) is estimated at 125 feet (38 meters). Thus, the proposed stack height is within the allowable limits.

3.3.2 New Source Performance Standards (NSPS)

The CAA required the U.S. EPA to adopt standards of performance for new or modified stationary sources of air pollution. To date, the U.S. EPA has adopted regulations for approximately 60 stationary source categories. These regulations are contained in 40 CFR Part 60, and incorporated by reference in Ch.17-296.800 F.A.C. The CT is subject to a specific NSPS (Subpart GG). Any source subject to a specific NSPS is also subject to the general provisions of 40 CFR 60 Subpart A.

3.3.2.1 General Provisions

The general provisions of the NSPS regulations are found in 40 CFR 60 Subpart A. The general provisions specify the notification and recordkeeping requirements (40 CFR 60.7), compliance with standards and maintenance requirements (40 CFR 60.11), and the monitoring requirements (40 CFR 60.13) for each affected source.

3.3.2.2 Combustion Turbine Units

In general, CT units are covered in 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines which establishes emission limitations on both NO_x and SO_2. The NO_x emission limitation is set by the following equation:

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

where:

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

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

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

Fuel-bound nitrogen (percent by weight)	**F (NO_x percent by volume)**
N<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 (percent by weight).

Use of the equation results in emission limitations of 98.5, 94.4 and 105.8 parts per million on a dry volume basis (ppmvd) at 15 percent oxygen for the proposed unit when fired on natural gas, natural gas firing with power augmentation and fuel oil, respectively. The SO_2 emission limitations are set at 150 ppmvd corrected to 15 percent oxygen in the exhaust stream or a fuel sulfur content less than or equal to 0.8 percent by weight.

3.3.2.3 Excess Emissions

The EPA has adopted general and specific recordkeeping and reporting requirements relating to excess emissions in 40 CFR 60.7(b) and 40 CFR 60.334(c). The EPA requirements specify maintaining records and submittal of a quarterly report (calendar year) on excess emissions associated with start-ups, shutdowns, malfunctions, inoperative continuous emission monitoring systems, low water-to-fuel ratio, and fuel sulfur content greater than 0.8% by weight. The reporting requirement includes submittal of the quarterly report even when no excess emissions occur. EPA has not adopted any specific limits on the number of hours excess emissions are allowed during start-up, shut down or malfunctions from combustion turbine units regulated under 40 CFR Part 60 Subpart GG.

3.3.3 State-Specific and General Emission Standards

In addition to federal requirements, FDEP has adopted specific and general emission limiting and performance standards. These standards may be found in Ch.17-296 F.A.C. The requirements of these standards must be met along with any federal PSD or NSPS limitation or requirement.

3.3.3.1 General Emission Standards

The FDEP has adopted general particulate matter emission limits (Ch.17-296.310 F.A.C.) as well as general pollutant emission limits (Ch.17-2.620 F.A.C.). These limits apply when no specific emission standard is applicable. For the CT, a general opacity limit of not greater than or equal to 20 percent opacity applies as well as a prohibition on emitting air pollutants that cause or contribute to an objectionable odor.

3.3.3.2 Combustion Turbine Units

The FDEP has not adopted any state-specific emission standards in Rules 17-296 or 17-2.650 F.A.C. relating to the operation of a CT unit. The FDEP has adopted the NSPS requirements of Subparts A and GG by reference in Ch.17-296.800 F.A.C. Based on the current FDEP rules, the CT unit must meet the NSPS requirements as discussed in Section 3.3.2.2.

3.3.3.3 Excess Emissions

The FDEP has adopted standards relating to excess emissions in Ch.17-210.700 F.A.C. The rule allows excess emissions resulting from startup, shutdown, or malfunction of any source as long as best operational practices are applied and the excess emissions do not exceed two hours in any 24-hour period unless authorized by FDEP. The FDEP can authorize different excess emission parameters from other sources on a case-by-case basis.

3.4 SOURCE APPLICABILITY

3.4.1 Nonattainment Applicability

The PSD regulations apply to the proposed project due to the attainment status for Alachua County with respect to all criteria air pollutants. Further, the project site is not within 50 km of any designated nonattainment areas and is therefore not within the "area of influence" of any nonattainment area. Therefore, no nonattainment area rules apply to the proposed CT.

3.4.2 PSD Classification

Alachua County and the surrounding counties are designated as PSD Class II areas for SO_2, PM_{10}, and NO_2. The Deerhaven Generating Station is located approximately 90 km south of the Okefenokee National Wilderness Area and 110 km north-northeast of the Chassahowitzka Wilderness Area, the nearest PSD Class I areas. The Wilderness Areas are those portions of the National Wildlife Refuges which have been officially designated as wilderness.

3.4.3 Pollutant Applicability

Pollutant applicability for the proposed facilities is addressed in Sections 2.0 and 4.0 and briefly summarized here. The proposed project is considered to be a major modification of a major existing source under the PSD regulations. PSD review is required for any regulated pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 3-2. As shown in Table 3-4, the potential emissions for the proposed facilities will exceed the PSD significant emission rates for the following regulated pollutants: NO_x, SO_2, PM_{10}, and H_2SO_4. The proposed project is subject to PSD review for only these pollutants.

3.4.4 Ambient Air Quality Monitoring

Based upon the net increase in emissions from the proposed facility presented in Table 3-4, a PSD preconstruction ambient air monitoring analysis is required, as part of the air quality impact analysis for NO_2, SO_2, PM_{10}, and H_2SO_4. However, if the net increase in a source's impact of a pollutant is less than the *de minimis* air quality impact level, as shown in Table 3-3, then an exemption from the preconstruction ambient air quality monitoring requirement may be granted for that pollutant. In addition, if an acceptable ambient air monitoring method for the pollutant has not been established by EPA, monitoring is not required.

Prior to commencement of preconstruction ambient air quality monitoring, preliminary modelling was conducted to indicate those pollutants which could be exempted from the monitoring requirement. As verified by the revised modelling analysis described in Sections 6.0 and 7.0, the increases in air quality impacts for NO_2, SO_2, and PM_{10} are predicted to fall

TABLE 3-4
MAXIMUM POTENTIAL ANNUAL EMISSIONS (SIMPLE CYCLE UNIT)
AND PSD SIGNIFICANCE VALUES

Pollutant	Emissions[1] (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Required (Yes/No)
Carbon Monoxide	97.35	100	No
Nitrogen Oxides	276.42	40	Yes
Sulfur Dioxide (0.25% S)[2]	265.2	40	Yes
Sulfur Dioxide (0.05% S)[2]	73.57	40	Yes
Particulate Matter (PM_{10})	21.65	15	Yes
Total Suspended Particulates (TSP)	21.65	25	No
Volatile Organic Compounds	8.99	40	No
Lead[3]	0.058	0.6	No
Asbestos	Neg.	0.007	No
Beryllium[3]	0.00033	0.0004	No
Mercury[3]	0.0009	0.1	No
Vinyl Chloride	Neg.	1	No
Total Fluorides	Neg.	3	No
Sulfuric Acid Mist (0.25% S)[2]	23.94	7	Yes
Sulfuric Acid Mist (0.05% S)[2]	7.7	7	Yes
Hydrogen Sulfide	Neg.	10	No
Total Reduced Sulfur	Neg.	10	No

(1) Full-load operation; 59°F temperature (ISO conditions); 2,000 hours on fuel oil, 1,510 hours on gas, and 390 hours on gas with power augmentation.
(2) Emission estimates based on a maximum distillate fuel oil sulfur content of 0.05 and 0.25 percent.
(3) Based on AP-42, Section 3.1, Table 3.1-7(EPA, 1993).

Neg. = Negligible
TPY = Tons per year

Source: ENSERCH Environmental, 1994

below the *de minimis* impact levels presented in Table 3-3. There are no EPA approved PSD protocol ambient monitoring methods for H_2SO_4. Therefore, monitoring is not required for NO_2, SO_2, PM_{10}, or H_2SO_4.

4.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

4.1 INTRODUCTION

The project's potential annual emissions of the pollutants regulated under the PSD program and the associated PSD significant emission rates are presented in Table 3-4. As noted, the following pollutants will be emitted in quantities greater than the PSD significant emission rates and thus are subject to BACT:

- Nitrogen Oxides (NO_x)
- Sulfur Dioxide (SO_2)
- Sulfuric Acid Mist (H_2SO_4)
- Particulate Matter (PM_{10})

This BACT analysis addresses the control strategies and costs associated with achieving the most stringent emission levels currently being imposed by the regulatory agencies on similar projects. The BACT analysis also examines effects of control strategies on other pollutants not subject to BACT which are either considered hazardous air pollutants or emitted in *de minimis* quantities.

4.2 BACT PROCEDURES

When conducting a BACT analysis, a permit applicant is required to follow the procedures and guidelines established by the EPA as well as any requirements set by the State/Local regulatory agencies. Most of the EPA procedures and guidelines have been documented in recent publications and include:

- *"Draft Top-Down BACT Summary"* (EPA, 1990c),
- *"OAQPS Control Cost Manual, Fourth Edition"* (EPA, 1990d),
- *"New Source Review Workshop Manual"* (EPA, 1990a), and
- *"Alternative Control Techniques Document (ACT)* (EPA, 1993b).

Currently the EPA is not requiring applicants to follow the Top-Down BACT procedures since the agency is in litigation on their use. However, FDEP, which is the permitting authority in this case, is requiring applicants to follow these procedures. As such, this BACT analysis follows the Top-Down BACT procedures.

The first step in a top down BACT analysis is the identification of the most stringent emission limitation(s) being applied to similar projects. These most stringent emission limitations, normally considered to be the lowest achievable emission rate (LAER), are then treated as BACT unless the applicant can demonstrate that meeting these emission limitations is either technically infeasible or of unreasonable cost when considering economic, energy and environmental factors. Identification of these emission limitations began with a review of the EPA's BACT/LAER Clearinghouse (EPA, 1990b). This review was conducted electronically through direct access to the EPA's Bulletin Board on October 21, 1993. Information was obtained based on two search criteria: process name (turbine) and date inserted (1/1/92). Information on determinations entered prior to the selected insertion date had been collected under previous reviews, dating back to 1985. The analysis continued with the California Air Pollution Control Officer's Association (CAPCOA) BACT Clearinghouse (CARB, 1993). Information on CAPCOA's BACT Clearinghouse is provided to ENSERCH Environmental on a quarterly basis, with the most recent information covering activities through November 1993. The CAPCOA's BACT Clearinghouse divides gas turbines into two categories; those less than 23 mmBTU/hr of heat input and those greater. The part of the analysis concluded with a review of other technical documents (i.e., manufacturer's data, technical papers...) and recent permits issued by FDEP. The most stringent emission limitations identified are listed in Table 4-1, which contains information on both simple cycle units and combined cycle units.

Following the identification of the most stringent emission limitations, the applicant must determine if the emission source as proposed can meet these limits. If the emission source cannot meet these limitations, additional control options must be examined. If a control option is deemed technically feasible, the applicant must address any economic, energy or environmental impacts associated with the control option. The additional economic impact, expressed in terms of dollars per ton of pollutant controlled (incremental cost) associated with the additional control option must be addressed. The additional energy impact associated with the control option must be examined as well as any environmental impacts. Thus, technically

TABLE 4-1
COMBUSTION TURBINE
MOST STRINGENT EMISSION LIMITATIONS

Pollutant	Combined Cycle		Simple Cycle		Units
	NGF	FOF	NGF	FOF	
NO_X	3.5(1)(2)	11.7(1)(3)	5-8(4)	42(5)	ppmvd @15% O_2 (2), (3), (4), (5)
SO_2	N/A(6)	0.05(7)	N/A(6)	0.05(7)	Fuel %S by weight (5), (6)
PM_{10}/TSP	N/A(8)	N/A(8)	N/A(8)	N/A(8)	N/A(8)
H_2SO_4	N/A(6)	0.05(7)	N/A(6)	0.05(7)	Fuel %S by weight

(1) Used in BACT analysis.
(2) Based on CAPCOA (A330-478-91), with gas firing only, steam injection and SCR.
(3) Based on BACT/LAER Clearinghouse (VA-0161), with steam injection and SCR.
(4) Based on CAPCOA (A330-499-91), high temperature SCR, 5 ppmvd at steady state and 8 ppm during non-steady state conditions.
(5) Based on SD-0001, with water injection
(6) BACT is based on natural gas with 10 grains of total sulfur per 100 standard cubic foot of gas, per meeting with FDEP.
(7) Based on WI-0054, low sulfur fuel oil, 0.05 percent by weight.
(8) Based on good combustion practices.

NGF = Natural gas firing
FOF = Fuel oil firing

Sources: EPA BLIS Bulletin Board (919) 541-5472.
California Air Pollution Control Officer's Association - BACT Clearinghouse.

infeasible options are eliminated and the remaining control options are evaluated. Unreasonably expensive options are eliminated until a BACT level is chosen.

4.3 REQUIREMENTS AND ASSUMPTIONS

This BACT analysis assumes the installation of a nominal 74 MW simple cycle CT manufactured by General Electric (GE), model MS7001EA. The CT will be operated as an intermediate peaking unit for a maximum of 3,900 hours per year. The CT will be capable of operating in any of three modes; natural gas fired (NGF), natural gas fired with power augmentation (NGFPA) or fuel oil firing (FOF). The CT design parameters used in the BACT analysis are presented in Table 4-2. The BACT assumes that the CT will be fired on natural gas as the primary fuel with distillate fuel oil as back-up (a maximum of 2,000 hours per year) and that NGFPA operation will represent less than 10 percent of the total time (i.e. a maximum of 390 hours per year) that the CT is fired on natural gas.

Operation at ISO conditions have been selected for purposes of the BACT analysis. The ISO conditions are slightly cooler than the average annual daily temperature but higher than the annual average low temperature at the site. Use of ISO conditions will allow easy comparison between the proposed BACT emission levels and those of the EPA's New Source Performance Standards (NSPS) for Combustion Turbines (40 CFR 60 Subpart GG). Emission rates estimated by GE at the various operating temperatures, loads and conditions are included in Appendix A as part of this application.

The unit selected is one of GE's Dry Low NO_x CTs designed to minimize NO_x emissions during NGF operation through staged combustion without the aid of water or steam injection. During NGFPA and FOF operations the CT will rely on water injection to control the NO_x emissions. PM_{10} emissions are controlled through good combustion practices as well as pre-filtering of the combustion air. SO_2 and H_2SO_4 emissions are controlled through fuel quality. These control strategies represent the baseline of the potential CT emission estimates.

4.4 NITROGEN OXIDE EMISSIONS

Formation of NO_x in a combustion process follows one of three basic chemical mechanisms. The first mechanism is known as thermal NO_x and occurs through the dissociation and subsequent reaction of the nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. These reactions are favored under conditions of high temperatures and elevated pressures. This mechanism follows the general equations:

TABLE 4-2
COMBUSTION TURBINE DESIGN PARAMETERS[1]

Number of Emission Units:	1
Unit Type	Dry Low NO_x Combustion Turbine
Cycle Type	Simple-Cycle
Service Type	Intermediate Peaking

	Fuels		
Parameter	**Natural Gas**	**Natural Gas with Power Augmentation**	**Fuel Oil**
Output (MW)	82.81	89.58	85.58
Exhaust Temperature (°F)	989	990	981
Heat Rate (BTU/KW HR) (HHV)	11,790	12,300	11,640
Fuel Flow (mmBTU/HR)	971.1	1,096.6	990.6
Fuel Flow (LB/HR)	40,700	45,920	50,380
Maximum Operating Hours[2]	3,900	390	2,000
Emission Rates			
NO_x - Lbs/hr[3]	53	120	213
SO_2 - (0.25% S) Lbs/hr[4]	26	30	240
SO_2 - (0.05% S) Lbs/hr[4]	26	30	48
PM_{10}/TSP - Lbs/hr[5]	7	7	15
H_2SO_4 - (0.25% S) Lbs/hr[6]	2.8	3.1	25
H_2SO_4 - (0.05% S) Lbs/hr[6]	2.8	3.1	5

(1) All data is based on 100 percent load at ISO conditions.
(2) Maximum requested operating times for each of the fuels, with a total combined maximum time operating of 3,900 hrs/yr.
(3) Nitrogen oxide emission rates are based on 15/30/54 ppmvd @ 15 percent oxygen for NGF, NGFPA and FOF, respectively. For FOF the emission reflects a maximum fuel bound nitrogen content of 0.03 percent by weight (42 ppmvd + 12 ppmvd).
(4) Sulfur dioxide emission rates based on a maximum of 10 grains of total sulfur per 100 standard cubic feet of natural gas and a maximum fuel oil sulfur content of 0.25 and 0.05 percent by weight with 95.1 percent conversion of sulfur to SO_2.
(5) Particulate matter emission rates do not include sulfuric acid mist emissions.
(6) Sulfuric acid emission rates based on a 6.5 percent conversion rate of the sulfur in the fuels and a maximum of 10 grains of total sulfur per 100 standard cubic feet of natural gas and a maximum fuel oil sulfur content of 0.25 and 0.05 percent by weight.

Source : ENSERCH Environmental, 1994

Dissociation

$$N_2 \leftrightarrows 2N$$
$$O_2 \leftrightarrows 2O$$

Reaction

$$N_2 + O \rightarrow NO + N$$
$$O_2 + N \rightarrow NO + O$$
$$N + O \rightarrow NO$$

The second mechanism is known as fuel NO_x and occurs through the oxidation of fuel-bound nitrogen during the combustion process. The actual reaction mechanism is quite complex with a variety of possible intermediates. The reaction follows the general equations:

$$H_xC_yN_z + wO_2 \rightarrow (x/2)H_2O + (y)CO_2 + zNO$$
$$H_xC_yN_z + wO_2 \rightarrow (x/2)H_2O + (y)CO_2 + (z/2)N_2$$

The third mechanism is known as prompt NO_x and occurs through the reaction of nitrogen radicals (NO) with the fuel's hydrocarbons (HC) to form intermediates which are further oxidized through the second mechanism. The reaction follows the general equations:

$$NO + C_xHy \rightarrow C_xH_{y-2}N + H_2O$$
$$C_xH_{y-2}N + zO_2 \rightarrow NO + (y-2)/2\ H_2O + xCO_2$$

In order to reduce and control NO_x emissions various technologies focusing on these mechanisms and NO_x chemistry have been used. These control technologies include wet controls, combustion controls and post-combustion controls. Wet controls and combustion controls focus on controlling the production of thermal NO_x by reducing peak flame temperature. Post-combustion controls focus on converting NO_x to N_2 through favorable conditions and mechanisms.

Since control technologies exist which can reduce emissions of NO_x from the CT, the BACT analysis must address their technological feasibility and costs, including consideration of their associated economic, energy and environmental factors associated with meeting the most stringent emission limitations.

4.4.1 Technological Feasibility Analysis

Current control strategies used to reduce and control NO_x emissions include:

- Wet Injection Techniques,
- Dry Low NO_x Combustors, and
- Selective Catalytic Reduction (SCR).

Based on review of the various clearinghouses and recent permits issued by the FDEP the most stringent emission limitations currently being imposed on combined cycle combustion turbines are 3.5 parts per million by volume on a dry basis (ppmvd), corrected to 15 percent oxygen when firing natural gas and 11.7 ppmvd, corrected to 15 percent oxygen when firing distillate fuel oil. Both of these limitations are based on the use of a post combustion control technology.

The following overviews represent the most current information available with respect to combustion turbine control technologies. Only a cursory overview has been provided for wet injection, as this is a well-established, consistently demonstrated technology used for the control of NO_x emissions, and is considered part of the base control technology for this project.

4.4.1.1 Wet Injection Techniques

Wet injection (water or steam injection) has been a proven technology for several years, and is currently used on the majority of the recently manufactured combustion turbines. Water suppression controls NO_x emissions by lowering the flame temperature, which reduces thermal NO_x formation. Water injection technology has had few recent technological advances; however, it continues to be the most effective NO_x suppressor for oil-fired operations. Advanced water injection systems, such as General Electric's multi-nozzle quiet combustor (MNQC), are capable of achieving 25 ppm during gas-fired operation and 42 ppm during oil-fired operation.

4.4.1.2 *Dry Low-NO_x Combustors*

Dry low-NO_x combustor designs control the fuel and air flows within the combustion zone to minimize thermal NO_x formation by limiting the peak combustion temperature and/or residence time. Fuel staging and air staging within the combustion zone may be used to establish fuel-lean or fuel-rich zones (above or below the stoichiometric amount of combustion air) in order to minimize flame temperatures. Several manufacturers have been involved in the development of dry low-NO_x combustion systems during the last decade.

Dry low-NO_x combustion technology is rapidly becoming the most popular choice for new combustion turbine installations. Several vendors will guarantee turbine emissions of NO_x in the range of 25 ppm to 9 ppm utilizing dry combustion technologies depending upon unit delivery dates. For units in operation, dry low-NO_x combustors can limit NO_x concentrations in natural gas fired turbine exhaust to 25 ppm; oil firing operations on dry low-NO_x combustors limit NO_x emission to 65 ppm without the use of water or steam injection.

Further refinements in dry low-NO_x combustion technology are resulting in predictions of lower NO_x emissions guarantees for future units ranging from 15 ppm to 9 ppm, when firing natural gas. GE has recently indicated that none of their current turbines are designed to meet 15 ppm, but are willing to guarantee a CT which is capable of achieving 15 ppm for delivery after the fourth quarter of 1994. CTs capable of achieving 9 ppm will not be available until about the 1998 time-frame.

4.4.1.3 *Selective Catalytic Reduction (SCR)*

Selective catalytic reduction (SCR) involves the injection of ammonia into the flue gas stream where it selectively reacts with NO_x in the presence of O_2 and a catalyst to form molecular nitrogen and steam. Because the pertinent reactions normally proceed at temperatures between 1600°F and 2200°F, a catalyst is used to promote the reactions at lower temperatures. Although exact catalyst compositions are proprietary, the use of base metal oxides (vanadium pentoxide, titanium dioxide, or noble metal) for both the active and support materials has been generally acknowledged. The temperature range required for the base metal catalytic reduction process to proceed is typically between 570°F and 750°F. Although some catalyst vendors have guaranteed effective NO_x reduction at higher temperatures, conventional catalyst degradation usually has occurred too rapidly to warrant the use of SCR to control NO_x emissions in higher temperature, simple cycle situations. Review of the information in the clearinghouses indicated no applications of a base metal catalyst on a simple cycle CT.

Recent technological advances in catalyst materials, may allow SCR to be an effective means of NO_x control at the higher temperatures typically encountered in simple cycle CTs. The addition of a zeolite-based catalyst to a conventional SCR system can extend the usually small temperature window required for the reduction reaction to proceed from approximately 570°F - 750°F to approximately 1050°F. In simple cycle units, exhaust gases are typically between 950°F and 1100°F. This is well above the operating temperature window of traditional base metal catalysts. Zeolite catalysts reportedly offer other benefits in addition to efficient NO_x removal at higher operating temperatures. According to the vendors, zeolite catalyst have been shown to have reduced conversion of SO_2 to sulfur trioxide (SO_3) when compared to base metal catalysts and to minimize ammonia slip, both of which will reduce particulate matter emissions due to the formation of ammonia salts in the stack exhaust. They also appear to be less susceptible to poisoning by sulfur-laden exhaust gases. Review of the information in the clearinghouses indicated only two applications of a high temperature zeolite catalyst. The first application was on a combustion turbine at a natural gas pipeline compressor station. The second and more recent application is proposed for three peaking units smaller than the proposed DHCT3. Both of these projects are located in California.

4.4.1.4 Technological Feasibility Summary

The CT selected is designed to use both dry low NO_x combustion technology and water injection to control NO_x emissions during NGF/NGFPA and FOF, respectively. Both of these technologies are considered to be available and technically feasible for this project. However, neither of these technologies will be capable of meeting the most stringent emission limitations identified under Section 4.2. Since the CT cannot meet the most stringent emission limitations with combustion controls alone, an analysis of the addition of a post-combustion control system must be made.

For CTs, the only post-combustion control technology currently available is SCR. For a simple cycle CT, the use of a standard base metal catalyst in the SCR system has been determined to be technically infeasible based on its effective operating temperature range.

The proposed application of the high temperature zeolite catalyst on two California projects required further analysis prior to determining technical feasibility. The first project involves a simple cycle Solar Model H CT fired on natural gas only which will be used to drive two centrifugal base load compressors. This CT is much smaller than the proposed DHCT3 and has a lower exhaust temperature. The second project involves three simple cycle GE Frame 5 CTs which will be used as peaking units. Again, these units are smaller than the proposed

DHCT3 and are expected to have lower exhaust temperatures. To date neither of these units are operational. However, available vendor information indicates that the zeolite catalysts are capable of operating at temperatures as high as 1,100°F. Based on the GE data sheets for the proposed DHCT3, exhaust temperatures will range from 995°F to 1,100°F, depending upon the fuel fired, ambient temperature and load. Since the zeolite catalysts were reported to operate in this temperature range, ENSERCH Environmental investigated the technical feasibility of using such a system. Because the zeolite catalysts are new, only one vendor (Norton Chemical Process Products Corporation, P.O. Box 350, Akron, Ohio 44309-0350) was capable of providing a cost estimate. A second vendor was contacted and a cost estimate requested but no response was received. The initial cost estimate received by ENSERCH Environmental is contained in Appendix B. This cost estimate noted that their current zeolite catalyst is limited to a maximum upper temperature of 1,050°F and that without an air injection system to cool the exhaust gases at the zeolite catalyst, its use would be infeasible. Review of the GE data sheets for the Deerhaven CT confirmed the vendor's exhaust gas temperature findings. However, since the maximum temperature limit of the zeolite catalyst would be reached only occasionally (i.e., loads < 100%), ENSERCH Environmental requested the vendor to revise the initial cost estimate and include the cost of an air injection system. The revised cost estimate is provided in Attachment C.

Based on the information obtained from the vendor, the use of a SCR system equipped with a zeolite catalyst and an air injection system was deemed to be only potentially technically feasible. It was deemed to be only potentially technically feasible based upon its limited usage on simple cycle CTs. In addition, although the concept of an air injection system is easily visualized, its use commercially has been documented only once in the clearinghouses as a commercially available response to the temperature limitations of SCR. Although only potentially technically feasible, ENSERCH Environmental evaluated the impacts of an SCR system equipped with a high temperature zeolite catalyst and an air injection system as the available post-combustion control technology needed to meet the most stringent emission limitations. This control strategy is referred to as Option #1.

A summary of the various control strategy options considered is included in Table 4-3.

4.4.2 Economic Impacts Analysis

The EPA's *Alternative Control Techniques Document (ACT)*, (EPA, 1993b) published in January of 1993 addresses the various control technologies available for use with a CT to reduce NO_x emissions. The ACT also examined the costs associated with the installation and

TABLE 4-3
SIMPLE CYCLE UNIT
NO_x CONTROL TECHNOLOGY FEASIBILITY SUMMARY

Control Strategy	Emission Limits[1]			Feasibility Analysis	Option #
	NGF	NGFPA	FOF		
Dry Low NO_x combustors, water injection and SCR with a base metal catalyst.	3.5	3.5	11.7	Technically infeasible due to the temperature limitations of the base metal catalysts.	N/A
Dry Low NO_x combustors, water injection and SCR with a zeolite catalyst and an air injection system.	3.5	3.5	11.7	Potentially technically feasible. However, only one small CT currently noted as operating in the U.S. Commercial application is currently questionable.	1
Advanced dry low NO_x combustors and water injection	9.0	30	54[2]	Technically infeasible due to the availability of the advanced units (i.e., >1998).	N/A
Dry Low NO_x combustors with water injection	15	30	54[2]	Technically feasible and considered as the base control strategy for this project.	2

(1) Emission limits expressed in terms of parts per million volume on a dry basis (ppmvd) corrected to 15 percent oxygen.
(2) 42 ppmvd plus an allowance for the fuel bound nitrogen up to a maximum of 54 ppmvd corrected to 15 percent oxygen.

NGF = Natural gas firing
NGFPA = Natural gas firing with power augmentation
FOF = Fuel oil firing
N/A = Not applicable (not a feasible option)

Source: ENSERCH Environmental, 1994

operation of these technologies. Because of the comprehensive nature of the ACT document, its costing strategies were used throughout this BACT analysis where applicable.

The ACT has reported cost effectiveness values of \$154/ton for dry low NO_x CTs with NGF and \$575/ton and \$403/ton for water injection associated with NGF and FOF, respectively. Cost effectiveness is expressed in terms of dollars per ton of NO_x removed. The ACT's reported cost effectiveness value for the SCR was \$6,980/ton and was based on meeting a NO_x limitation of 9 ppmvd, corrected to 15 percent oxygen. Since the costs of the dry low NO_x and water injection systems are considered as part of the CT's base package, these costs were not considered in this economic impact analysis. In addition, the ACT's cost effectiveness value for SCR was not used since it does not adequately represent the BACT analysis procedures which must address reducing emissions to those of the most stringent emission limitations (3.5 ppmvd). ENSERCH Environmental's concern regarding the ACT's cost estimate was based on the additional catalyst needed to reduce emissions from the already low CT rates to those of the most stringent emission limitations. Although the emissions reductions were different in the two analyses, the final costs (\$6,672.58/ton) determined for this project did not vary significantly from those of the ACT.

4.4.2.1 Capital Cost Estimate

In developing the capital cost estimate the BACT analysis followed the standard engineering cost estimating procedures outlined in the EPA's *Control Cost Manual* (EPA, 1990d), Gael Ulrich's "*A Guide To Chemical Engineering Process Design And Economics*" (Ulrich, 1984a) and the ACT. The capital cost estimate was based on the vendor quote on the basic equipment. Cost factors for all equipment and operations not covered by the quote, were based on the above references.

The vendor's quote for the GRU DHCT3 included the SCR modules, hot wall reactor housing, ammonia injection grid, ammonia dilution and flow control skid, ammonia storage tank, engineering specifications, continuous monitoring system for ammonia slip and the air injection system for an estimated cost of \$3,279,000. The capital cost factors used to develop the total capital investment (TCI) estimate are presented in Table 4-4 for an SCR system equipped with a zeolite catalyst and an air injection system.

The direct costs associated with the SCR system are the purchased equipment costs (PEC) and direct installation costs (DIC). The PEC includes the SCR and associated auxiliary equipment, instrumentation, sales taxes and freight. The SCR, auxiliary equipment and

TABLE 4-4
SIMPLE CYCLE UNIT
CAPITAL COST FACTORS FOR SELECTIVE CATALYTIC REDUCTION

Cost Item	Factor	Reference
Direct Costs (DC)		
Purchased Equipment Costs (PEC)		
SCR & Auxiliary Equipment	As estimated, A	Vendor quote
Instrumentation	N/A	Vendor quote
State Sales Taxes	N/A	Exempt
Freight	0.05 x A	EPA, 1990d
PEC Subtotal	1.05 x A = B	
Direct Installation Costs (DIC)		
Foundations & Supports	0.08 x B	Ulrich, 1984a
Labor	0.14 x B	EPA, 1990d
Electrical	0.04 x B	EPA, 1990d
Piping	0.04 x B	EPA, 1990d
Insulation	N/A	Vendor quote
Painting	0.01 x B	EPA, 1990d
DIC Subtotal	0.31 x B	
Site Preparation	N/A	Existing site
Buildings	N/A	Existing site
Total DC	**1.31 x B**	
Indirect Costs (IDC)		
Engineering	0.15 x B	Ulrich, 1984a
Construction Overhead	0.05 x B	EPA, 1990d
Contractor Fees	0.10 x B	EPA, 1990d
Contingencies	0.20 x B	GRU/ENSERCH
Start-up	0.02 x B	EPA, 1990d
Performance Testing	0.01 x B	EPA, 1990d
Total IDC	**0.53 x B**	
Total Capital Investment = DC + IDC	**1.84 x B**	

Source: ENSERCH Environmental, 1994

instrumentation were all included in the vendor's quote. The state sales taxes were excluded from the cost analysis since GRU is a tax exempt municipality. Freight charges were assumed to be five percent (EPA, 1990d) of the vendor's quote. The DIC includes foundations and supports, construction labor, electrical, piping, insulation and painting costs. The foundations and supports costs were based on a cost factor of eight percent (Ulrich, 1984a). The labor, piping, electrical and painting costs were based on cost factors of fourteen, four, four and one percent, respectively (EPA, 1990d). Insulation costs were included in the vendor's quote. Site preparation costs and costs associated with additional buildings were neglected since the site is an existing facility.

The indirect costs associated with the SCR system include engineering, construction overhead, contractor fees, contingencies, startup and performance testing costs. For engineering costs a fifteen percent cost factor (Ulrich, 1984a) was used since the zeolite catalyst represents a new technology. Similarly, the contingency cost was set at twenty percent, a value which has been used in other recent BACT analyses involving SCR systems and accepted by FDEP. The construction overhead, contractor fees, startup and performance testing costs were based on cost factors of five, ten, two and one percent, respectively (EPA, 1990d).

The TCI estimation based on the vendor's quote and the above cost factors is presented in Table 4-5. The total estimated cost is approximately 6.3 million dollars or approximately 1.84 times that of the vendor's quote. One reference document indicates that the TCI costs can be expected to be between three and five times (Ulrich, 1984a) the cost of the basic equipment. The EPA documents indicate that costs of 1.26 (EPA, 1993b) and 1.61 (EPA, 1990d) can be expected. Based on the TCI developed from the cost factors, it was determined that the estimate generated by this analysis is reasonable for the project and within good engineering practices.

4.4.2.2 Operating Cost Estimate

The operating cost estimate was based on the data contained in the ACT with cost data adjusted from 1990 dollars to 1993 dollars based on the *Chemical Engineering Plant Cost Index* (August, 1993). The annualized cost figures are based on a 15-year economic life of the SCR system, at an annual interest rate of seven percent.

The operating costs consist of direct and indirect annual costs. The direct annual costs include operating labor, supervisory labor, maintenance labor and materials, catalyst replacement, catalyst disposal, anhydrous ammonia, ammonia dilution system, electricity,

TABLE 4-5
SIMPLE CYCLE UNIT
TOTAL CAPITAL INVESTMENT FOR SELECTIVE CATALYTIC REDUCTION

Cost Item	Estimated Cost (1993$)
Direct Costs (DC)	
Purchased Equipment Costs (PEC)	
SCR & Auxiliary Equipment	$3,279,000.00
Instrumentation	--
State Sales Taxes	--
Freight	163,950.00
PEC Subtotal	$3,442,950.00
Direct Installation Costs (DIC)	
Foundations & Supports	$275,436.00
Labor	482,013.00
Electrical	137,718.00
Piping	137,718.00
Insulation	--
Painting	34,429.50
DIC Subtotal	$1,067,314.50
Site Preparation	--
Buildings	--
Total DC	**$4,510,264.50**
Indirect Costs (IDC)	
Engineering	$516,442.50
Construction Overhead	172,147.50
Contractor Fees	344,295.00
Contingencies	688,590.00
Start-up	68,859.00
Performance Testing	34,429.50
Total IDC	**$1,824,763.50**
Total Capital Investment = DC + IDC	**$6,335,028.00**
Source: ENSERCH Environmental, 1994	

performance loss, and air injection system costs. The indirect annual costs include overhead, property taxes, insurance and administration, and capital recovery costs. The capital recovery costs are based on the TCI estimate. The operating cost data are contained in Table 4-6.

Operating and supervisory labor costs were estimated based on 1-hour of operating labor per 8-hour shift for a maximum of 3,900 hours per year at $25.60 per hour (EPA, 1993b) in 1990 dollars. Supervisory labor costs were estimated at 15 percent of the operating labor costs (EPA, 1993b).

Maintenance labor and materials (MLM) costs were estimated (EPA, 1993b) based on the turbine output ($=1,250 X MW + 25,800) in 1990 dollars.

The catalyst replacement costs were estimated based on the vendor's quote of $934,731.00 per layer with an estimated catalyst life of three years or 24,000 hours, whichever comes first. The vendor's quote noted that two layers are required to meet the most stringent emission limitations. The BACT analysis assumed that the catalyst would last five years and that during the economic life of the SCR it would need to be replaced twice.

The catalyst disposal costs were estimated based on a required 8,281 cubic feet (CF) of catalyst with three disposals required over the 15 year period at a cost of $15/CF (EPA, 1993b) in 1990 dollars.

The anhydrous ammonia costs were estimated based on a required 1 to 1 mole ratio of ammonia to NO_x removed by the SCR system plus a ten percent safety/loss factor and ammonia costs of $360/ton in 1990 dollars (EPA, 1993b).

For the ammonia dilution system the annual costs were estimated from a cost factor (EPA, 1993b) based on the amount of ammonia used and a cost of $6 per 1000 pounds of steam needed to vaporize the ammonia, in 1990 dollars.

Electricity costs associated with the ammonia injection system were reportedly small in the ACT and thus ignored. The BACT analysis assumed the same and this cost was neglected. The total performance loss costs were based on a 0.5 percent loss of the units output capacity due to the back pressure associated with the SCR system. This cost is estimated based on lost electrical sales at $0.06/KWH, in 1990 dollars.

TABLE 4-6
DEERHAVEN CT3
OPERATING COST FACTORS/PARAMETERS FOR SELECTIVE CATALYTIC REDUCTION[1]

A. Cost Factors	
Chemical Engineering Plant Cost Index[2]:	1990 - 357.6
	April 1993 - 358.0
Capital Recovery Factor (CRF)[3]:	0.1098
B. Total Capital Investment (TCI)[4], $	$6,335,028.00
C. Direct Annual Costs, $/yr	**Parameter**
1. Operating Labor[4]	= (1hr/8hr-shift) x ($25.60/hr) x (H)
2. Supervisory Labor	= (0.15) x (operating Labor)
3. Maintenance Labor and Materials[4]	= (1,250 x MW + 25,800)
4. Catalyst Replacement[5] (CR)	= (2 layers) x (2 changes) x CR x CRF
5. Catalyst Disposal[4]	= (3 changes) x (8,281 CF/change) x ($15/CF) x CRF
6. Anhydrous Ammonia[4]	= (N) x ($360/ton) x (1.10)
7. Dilution System[4]	= (N) x (.95/.05) x (MW_{H2O}/MW_{NH3}) x ($6/1000 lb steam) x (2,000 lb/ton)
8. Electricity	= N/A
9. Performance Loss[4]	= (0.005) x (MW) x ($0.06/KWH) x (1,000 KW/MW) x (H)
10. Blower[6]	= ($0.746Q\Delta Ps\theta p/6356\eta$)
11. Production Loss	= None
D. Indirect Annual Costs, $/yr	**Parameter**
1. Overhead	= (0.6) x (all labor and maintenance material costs)
2. Insurance and Administration	= (0.025) x (TCI)
3. Capital Recovery	= (CRF) x (TCI - CR)

(1) Based on information from the Control Cost Manual (EPA, 1990d) and the ACT (EPA, 1993b).
(2) As published in the *Chemical Engineering* magazine, August, 1993.
(3) Based on 7 percent interest and an economic life of 15 years.
(4) Based on Table 6-8, page 6-20 of the ACT (EPA, 1993b).
(5) Based on the vendor quote.
(6) Based on Equation 2.7, page 2-26 of the Control Cost Manual (EPA,1990d)

CF = cubic feet
N = net reductions of NO_x in tons per year

Source: ENSERCH Environmental, 1994

The air cooling system costs were based on a required air flow of 32,000 SCFM and equation 2.7 of the EPA Control Cost Manual (EPA, 1990d).

The indirect overhead costs were based on the labor and maintenance material costs. A cost factor of 60 percent (EPA, 1993b) was used to estimate this cost.

The insurance and administrative (IA) costs were based on 2.5 percent (EPA, 1993b) of the TCI.

The capital recovery costs were based on the annualized cost of the TCI excluding catalyst costs based on 15 years and a seven percent interest rate.

For this project the total annual costs were estimated at $1,455,957.53 per year. The costs are summarized in Table 4-7.

4.4.3 Energy Impact Analysis

Use of the SCR system, referred to as Option #1, will result in an overall reduction in the CTs' performance and output capacity. The main loss is associated with the additional pressure drop across the ammonia injection grid and the catalyst bed. This pressure drop has been estimated at 4.5 inches of water and can reduce turbine output by as much as 0.5 percent or 1.44 million-kilowatt-hours per year. In addition, energy is also required to pump and store the anhydrous ammonia, run the air injection system and operate the additional process control equipment. Although the losses associated with an SCR are measurable, they are not, by themselves, considered significant enough to warrant rejection of the control strategy.

Use of dry low NO_x combustors and water injection (Option #2) also result in losses. However, these losses are not considered significant and are considered as part of the base package for the CT.

4.4.4 Environmental Impact Analysis

The use of either of the NO_x control technologies (Option #1 or Option #2) will result in additional environmental impacts from the CT. These impacts include higher emission rates for various air pollutants other than NO_x, use of valuable natural resources and increased solid waste disposal requirements.

TABLE 4-7
DEERHAVEN CT3
OPERATING COSTS FOR SELECTIVE CATALYTIC REDUCTION

A. Total Capital Investment, $	$6,335,028.00
B. Direct Annual Costs, $/yr	**Cost**
1. Operating Labor	= 12,466.06
2. Supervisory Labor	= 1,869.91
3. Maintenance Labor and Materials	= 118,167.82
4. Catalyst Replacement	= 410,513.76
5. Catalyst Disposal	= 40,868.70
6. Anhydrous Ammonia	= 31,897.42
7. Dilution System	= 19,455.48
8. Electricity	= N/A
9. Performance Loss	= 86,483.26
10. Blower	= 6,072.00
11. Production Loss	= None
C. Indirect Annual Costs, $/yr	**Cost**
1. Overhead	= 79,502.27
2. Insurance and Administration	= 158,375.70
3. Capital Recovery	= 490,295.14
D. Total Annual Costs, $/yr	**$1,455,957.53**

Source: ENSERCH Environmental, 1994

An SCR system (Option #1) requires the use of ammonia (which is listed by EPA as an extremely hazardous substance). This use presents several problems. The reactions controlling NO_x emissions will not consume all the ammonia injected into the exhaust gas stream. This is known as ammonia slip. A 10 ppm ammonia slip in the exhaust gases amounts to nearly 30 tons of ammonia being released each year. There are also concerns about secondary emissions resulting from the continuous introduction of ammonia into the stack gases, such as the formation of nitrous oxide and nitrosoamines. In addition to the continuous release of ammonia, the threat of an accidental release of ammonia associated with its transportation, handling and storage must be addressed. When considering that approximately 300 tons of anhydrous ammonia will be needed annually for the life of the project, the potential for an accidental release increases dramatically.

In addition to ammonia emissions, an SCR system will result in higher emissions of sulfur trioxide (SO_3), also an extremely hazardous substance. These higher emissions are associated with the additional oxidization of SO_2 to SO_3 across the catalyst. These SO_3 emissions can be expected to further react with ammonia to form ammonium bisulfate (NH_4HSO_4) and ammonium sulfate ($(NH_4)_2S0_4$). These emissions will be noted as increased particulate matter emissions. SO_3 can also be expected to form sulfuric acid when combined with the water vapor in the exhaust stack gases.

The spent catalyst from the SCR system will need to be replaced and properly disposed of every five years. This places additional burdens on existing landfill capacities.

Water usage, common to both options, represents approximately 12 million gallons of water per year.

Since the use of an SCR system equipped with a high temperature zeolite catalyst and an air injection system has not been operated in a commercial utility application, all the potential environmental impacts cannot be evaluated at this time. Environmental impacts associated with standard SCR systems have been considered to be significant.

4.4.5 NO_x BACT Summary

Table 4-8 summarizes the NO_x BACT findings. Based on this BACT analysis, an SCR system equipped with a zeolite catalyst and an air injection system in combination with wet injection and dry low NO_x controls would be required in order to meet the most stringent (top) emission limitations . Although determined to be potentially technically feasible, use of

TABLE 4-8
DEERHAVEN CT3
SUMMARY OF TOP-DOWN BACT IMPACT ANALYSIS RESULTS FOR NO_X

	Control Alternatives[1]	
	Option #2 15/30/54[2]	**Option #1 3.5/3.5/11.7**
Emissions		
Turbine (TPY)	276.42	58.22
Reductions (TPY)	Base	218.2
Economic Impacts		
Total Annual Costs ($/Yr)	Base	$1,455,957.53
Incremental Cost Effectiveness ($/Ton)	Base	$6,672.58
Energy Impact		
SCR Power Penalty (kW-Hr/Yr)	Base	1,443,000
Environmental Impacts		
Additional Hazardous Air Pollutant Emissions	No	Yes
Additional Solid Waste Generation	No	Yes
Ammonia Storage and Handling Required	No	Yes

(1) Option #1 - Selective cataltytic reduction
Option #2 - Dry low NO_x combustors and water injection
(2) 54 = 42 ppmvd + 12 ppmvd based on .03% FBN

Source: ENSERCH Environmental, 1994

the combination of control strategies would be unreasonable when considering the economic, energy and environmental impacts. For this project, an incremental cost effectiveness of \$6,672.58 per ton of NO_x removed to meet the most stringent emission limitation was determined based on the addition of a SCR system. This cost, when combined with the associated energy and environmental impacts, is higher than costs for the few projects where SCR has been required and was determined to be neither cost effective nor justifiable. Thus, Option #2, dry low NO_x combustors with water injection, was selected as BACT.

4.5 SULFUR DIOXIDE/SULFURIC ACID MIST EMISSIONS

Sulfur dioxide and sulfuric acid mist emissions are directly related to the sulfur content of the fuel fired in the CT. Review of the BACT/LAER Clearinghouse indicates that the most stringent emission limitations established for NGF and FOF CTs have been based on fuel quality (pre-combustion controls). This is consistent with past EPA findings that the use of add-on air pollution control systems for SO_2 and H_2SO_4 emissions from CTs are technically infeasible. The emission levels identified in Table 3-4 are based on a 95.1 percent conversion of the sulfur in the fuels to SO_2, based on the GE data sheets. In addition, emission levels for H_2SO_4 mist were estimated based on a maximum conversion of 6.5 percent of the sulfur in the fuel.

For NGF operation, a sulfur content of 10 grains per 100 standard cubic feet of gas was used for estimating emissions based on the maximum amount potentially present in the fuel. Use of this conservatively high sulfur content was discussed with the FDEP prior to submittal of this application.

As indicated previously, the proposed combustion turbine will use natural gas as the primary fuel, and very low sulfur fuel oil (0.05% sulfur by weight or lower) for backup fuel. For NGF operations, the use of natural gas is considered BACT for SO_2 and H_2SO_4. For FOF operations, the use of very low sulfur content fuel oil is considered BACT and is equivalent to the most stringent emission limitations recently imposed. Therefore, the proposed unit will meet BACT requirements through fuel specification.

GRU currently has approximately 387,000 gallons of 0.25% sulfur distillate fuel oil in inventory ("existing supply"). GRU anticipates that much of this existing fuel supply may be still in inventory when the proposed unit becomes operational in the summer of 1995. Accordingly, GRU is requesting that FDEP allow the initial use of this fuel oil in the proposed combustion turbine until the existing supply is drawn down to a minimum practical level (5,000 - 10,000 gallons). At that time, additional very low sulfur fuel oil would be added to the tank and would become the fuel used by the existing CTs and other existing usages of distillate fuel oil at the Deerhaven Generating Station in addition to the proposed CT.

GRU believes the request is reasonable and prudent for the following reasons:

- The distillate fuel oil storage and handling facilities at the Deerhaven Site are centralized and were recently upgraded to meet stringent environmental standards. The immediate use of very low sulfur fuel oil for the proposed CT would require the permitting and construction of new facilities.

- The continued use of a centralized facility would reduce operating costs and potential environmental risks associated with additional fuel loading, storage and transfer facilities.

- Assuming there will be no additional distillate fuel oil purchases at this site until the existing supply is drawn down, the existing supply will allow only approximately 54 hours of continuous full load operation at ISO conditions. As the unit startup and testing time on fuel oil is estimated at 30-50 hours, it is anticipated that the majority of the existing supply will be consumed during this initial start-up period.

- Subsequent distillate fuel oil purchases for this facility will be limited to 0.05% sulfur by weight or less. This fuel will also be used in the existing units as well as the proposed combustion turbine resulting in a potential for overall reductions in SO_2 emissions at the Deerhaven Site.

4.6 PARTICULATE MATTER (PM_{10}) EMISSIONS

Particulate matter emissions from CTs are related to the combustion air, fuel quality and combustion efficiency. Review of the BACT/LAER Clearinghouse indicates that most CTs meet the BACT requirement through filtering the combustion air, good combustion practices, use of clean burning natural gas and limited fuel oil firing. Currently, post combustion controls (i.e., baghouse) are not being used on CTs. This is due mostly to the very low PM_{10} emissions associated with CT operations.

PM_{10} emissions result from noncombustibles in the fuels, PM_{10} in the ambient air used as combustion air, dissolved solids in the water used for wet injection and incomplete combustion. Since solids can damage the CT, considerable efforts are made to limit their entry and/or formation. Based on this need and review of the BACT/LAER Clearinghouse data, GRU proposes prefiltering of the combustion air, good combustion practices, and use of natural gas as the primary fuel with limited annual fuel oil firing as BACT. Under these conditions, GRU has been given emission estimates of 7/7/15 pounds per hour of PM_{10} (excluding sulfuric acid mist) during NGF, NGFPA and FOF, respectively. These values represent emission levels of 0.008/0.0064/0.015 pounds per million Btu of heat input.

5.0 AMBIENT AIR QUALITY MONITORING DATA ANALYSIS

5.1 PSD PRECONSTRUCTION MONITORING APPLICABILITY

As indicated in Section 3.4.4, GRU evaluated the need for preconstruction on-site air quality monitoring in accordance with the requirements of Ch.17-212.400(3)(e). A monitoring exemption request was submitted to FDEP on November 24, 1993 and approved by FDEP on February 11, 1994 (FDEP, 1994). That request contained a brief description of the project and discussions of existing climate and air quality based on regional data as well as a preliminary air quality modelling assessment of the impacts of the proposed CT.

The preliminary modelling results demonstrated that the maximum off-site impacts from the proposed CT will be well below the monitoring significance levels for all of the criteria pollutants (Table 3-3). Those results are conservative as they were based on preliminary emission rates which are in some cases greater than the currently proposed emission rates for the proposed CT. The currently proposed emission rates were used for the revised modelling; the results are included in Section 7.0.

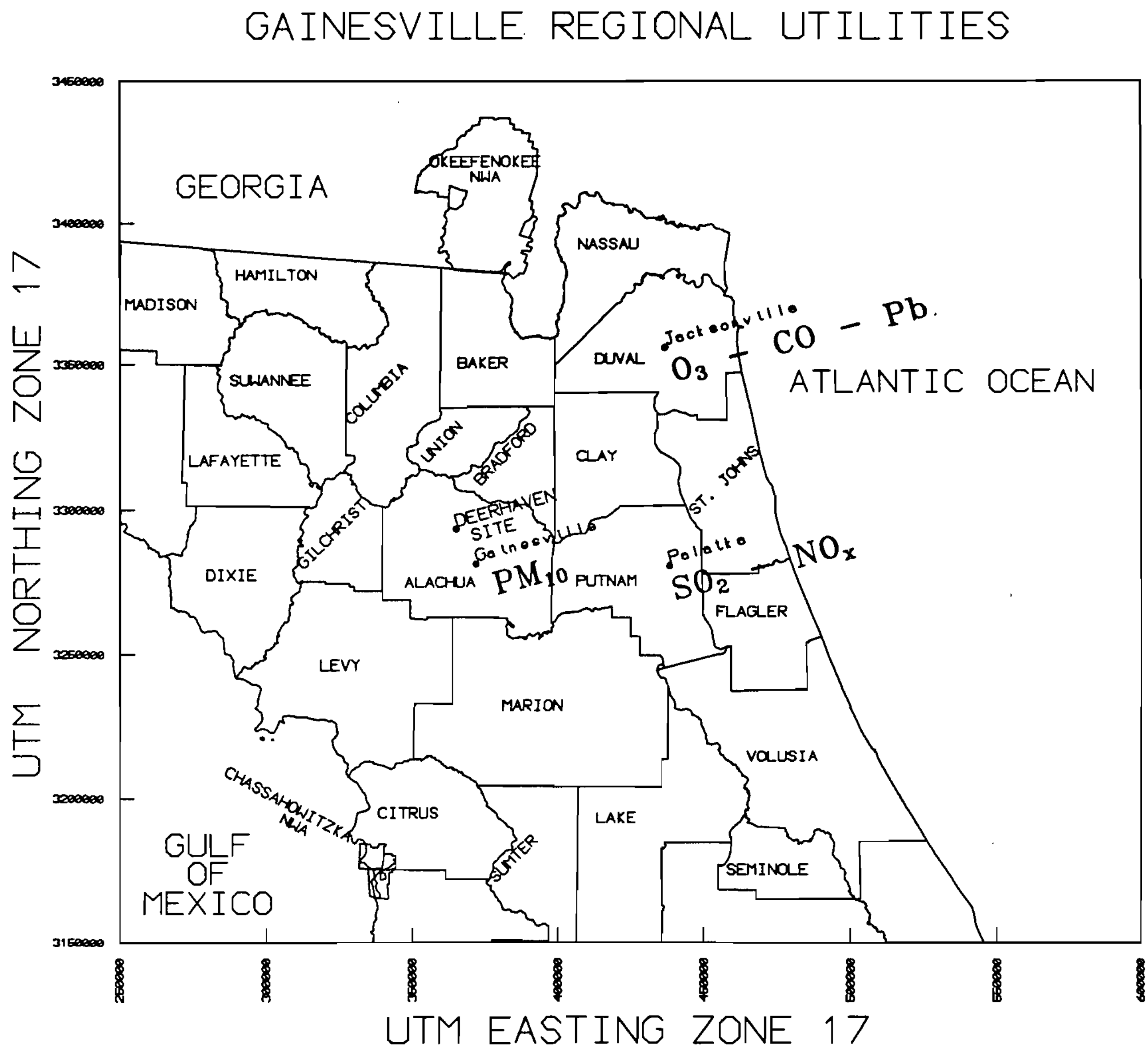
5.2 EXISTING REPRESENTATIVE AIR QUALITY MONITORING DATA

Existing FDEP and GRU ambient air monitoring data are available that can be used to characterize the existing conditions at and in the vicinity of the site. A map depicting the locations of the existing ambient air quality monitoring sites is presented as Figure 5-1. The FDEP and GRU data from these monitors for 1992 are summarized in Table 5-1.

Both FDEP and GRU collected ambient PM_{10} data in the vicinity of the site. The data from both sites indicate that existing PM_{10} concentrations are well below the NAAQS/FAAQS.

Concentrations of SO_2 and NO_2 have been measured by FDEP at Palatka and indicate that existing SO_2 and NO_2 concentrations at that nearby location are well below the NAAQS and FAAQS.

In the site region, ambient data for CO, O_3, and Pb have been collected by FDEP only in the Jacksonville metropolitan area. These pollutants are usually associated with urban environments. Given the rural nature of the project site, concentrations are expected to be significantly lower than those in Jacksonville.



Source: ENSERCH Environmental, 1994

GRU	**FDEP Ambient Air Quality Monitoring Stations (1992)**	**FIGURE** **5-1**

TABLE 5-1
1992 MONITORING DATA SUMMARIES
FOR NEARBY AIR QUALITY MONITORING SITES

Parameter	Station	SAROAD ID	Maximum 1-Hr(1)	Maximum 3-Hr(1)	Maximum 8-Hr(1)	Maximum 24-Hr(1)	Maximum Quarter(1)	Annual(1)
PM_{10}	Gainesville	1420023F02	N/A	N/A	N/A	44	N/A	22
PM_{10}	GRU (9/90-9/91)	N/A	N/A	N/A	N/A	38	N/A	18
SO_2	Palatka	3780008F02	338	216	N/A	23	N/A	9
Ozone	Jacksonville	1960070H01	223	N/A	N/A	N/A	N/A	N/A
NO_x	Palatka (Jan-Mar)	3780005J02	N/A	N/A	N/A	N/A	N/A	13
CO	Jacksonville	1960083H01	13	N/A	6	N/A	N/A	N/A
Lead	Jacksonville	1960084H01	N/A	N/A	N/A	N/A	0.0	N/A

(1) All values are in µg/m^3 except for CO which is in parts per million (ppm).

N/A = Not applicable

Source: GRU, 1991
FDEP, 1993

5.3 CLIMATOLOGY

The climate in northern Florida is classified as subtropical with maritime influences from both the Atlantic Ocean and the Gulf of Mexico. Summers are long, warm and relatively humid, while winters are mild because of the latitude and the warming influence of the Gulf Atlantic.

Climatological data representative of the site are available for the Gainesville Regional Airport, which is located approximately 15 km to the southeast. A summary of temperature and precipitation data for Gainesville, Florida is presented in Table 5-2.

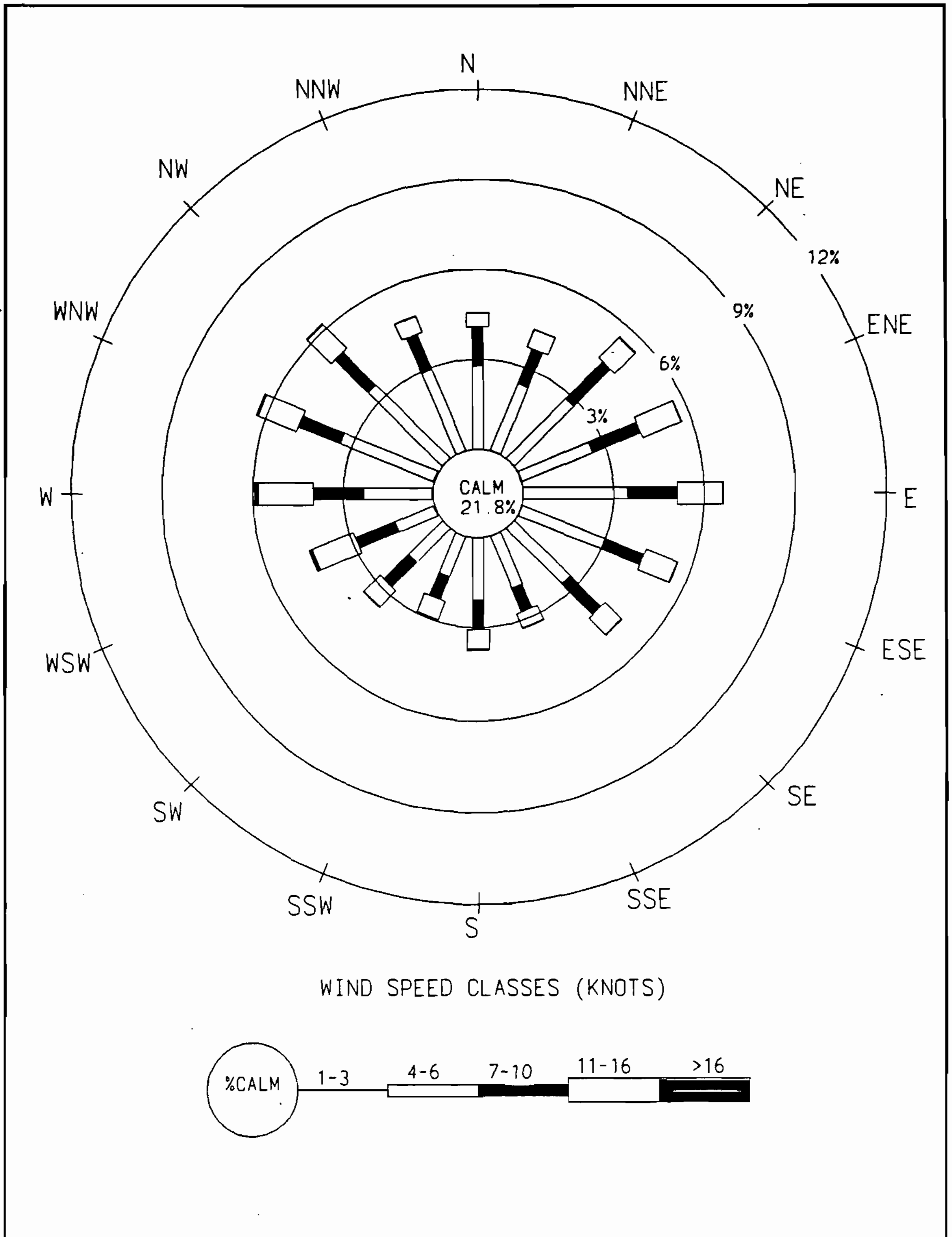
TABLE 5-2

Temperature and Precipitation Summary - Gainesville, Florida

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Ann
Mean Temp (°F)	54.6	56.4	62.4	68.4	74.6	79.0	80.8	80.8	78.5	70.3	61.9	56.0	68.6
Mean Max Temp (°F)	66.7	68.5	75.1	81.1	86.6	89.5	90.5	90.5	87.8	81.1	73.9	68.1	80.0
Mean Min Temp (°F)	42.5	43.7	49.7	55.7	62.5	68.4	71.0	71.1	69.2	59.4	49.8	43.9	57.2
Mean Precip (In)	3.23	3.92	3.53	2.94	4.14	6.34	6.99	8.07	5.50	2.45	2.04	3.24	52.39

Source: NOAA, 1989 (Period of Record 1951-1980)

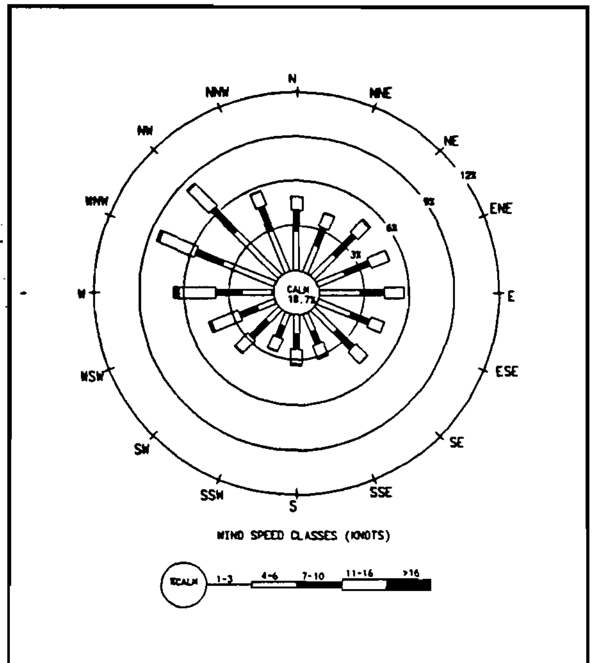
Five years of wind data selected to represent the Deerhaven Site were obtained from the National Weather Service station at the Gainesville Regional Airport. Based on these data, the annual average wind speed is 6.3 mph. The prevailing wind direction during the 1985-1989 time period was from the east, which occurred approximately seven percent of the time. Wind directions from the west, west-northwest, and northwest each occurred approximately six percent of the time. An annual wind rose for Gainesville for this time period is presented in Figure 5-2, and quarterly wind roses are presented in Figure 5-3.



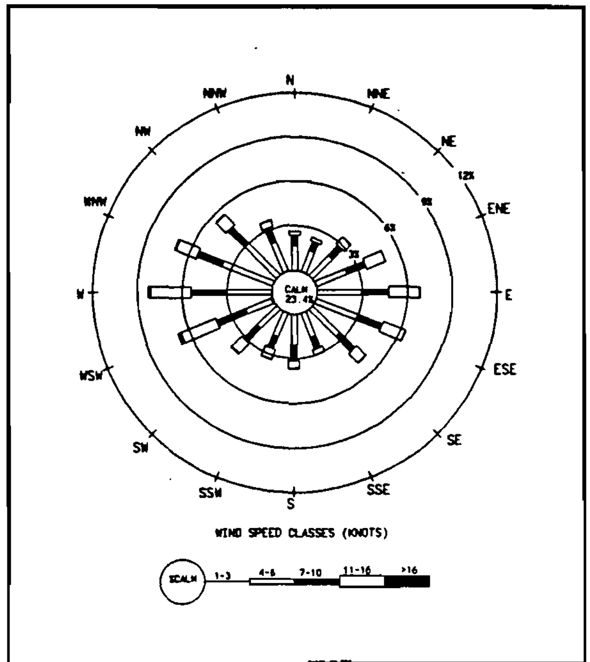
GAINESVILLE FLORIDA
1985 - 1989

Source: ENSERCH Environmental, 1994

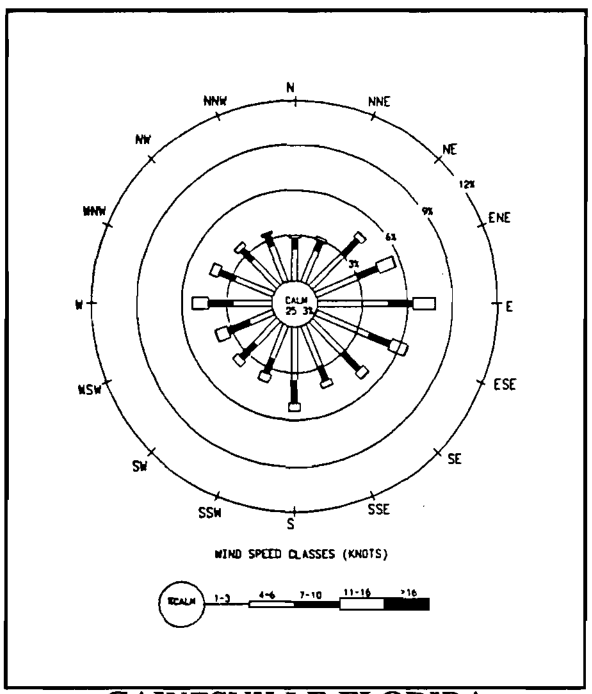
GRU	**Annual Wind Rose**	**FIGURE** **5-2**



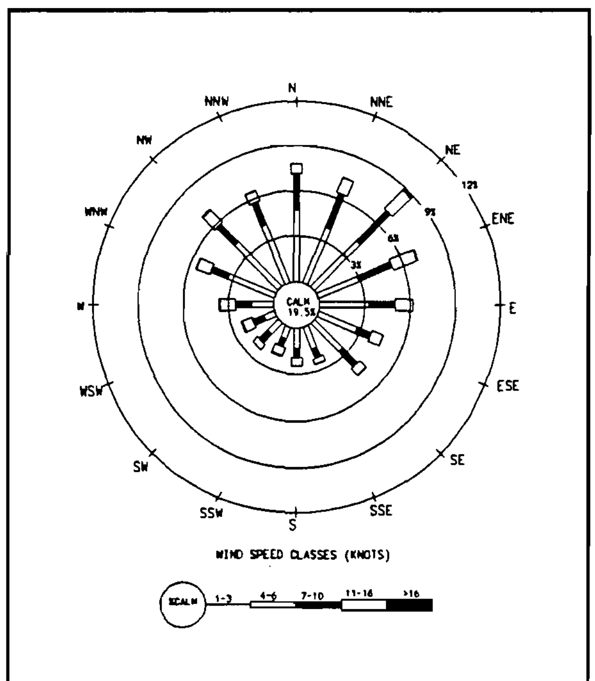
GAINESVILLE FLORIDA
1985 - 1989 JAN - MAR



GAINESVILLE FLORIDA
1985 -1989 APR - JUN



GAINESVILLE FLORIDA
1985 - 1989 JUL - SEP



GAINESVILLE FLORIDA
1985 - 1989 OCT - DEC

Source: ENSERCH Environmental, 1994

GRU

Quarterly Wind Roses

FIGURE
5-3

6.0 AIR QUALITY MODELLING APPROACH

This section summarizes the air quality modelling protocol and input parameters utilized in the air impact determinations presented in Section 7.0. Descriptions of the models, meteorology, options selected, listings of modelling parameters for the proposed CT, receptor locations, and step-by-step procedures that were used to develop the necessary projected impacts are discussed.

6.1 POLLUTANTS COVERED

The required modelling analysis is limited to those pollutants that were determined to be subject to PSD review in Section 3.4.3, Table 3-4 (NO_x, SO_2, PM_{10}, and sulfuric acid mist). Although the proposed source emissions of sulfuric acid mist are shown in Table 3-4 to be above the PSD significant emission rates there are no ambient air quality standards nor PSD significant impact levels or increments for this pollutant. Hence, the air quality impact assessment for sulfuric acid mist is limited to prediction of the maximum impacts from the proposed facility. Conventional modelling for compliance with AAQS and PSD increments was therefore restricted to NO_x, SO_2 and PM_{10}. Hazardous air pollutants (HAPs) not subject to PSD review but regulated under the CAA Amendments of 1990 for which emission estimates were available for this project (antimony, arsenic, cadmium, chromium, cobalt, formaldehyde, manganese, nickel and selenium) were also included in the air quality impact analysis.

6.2 GENERAL MODELLING APPROACH

As required by the PSD regulations, the air quality impact assessment consists of a proposed source impact assessment versus the monitoring significance levels, a significant impact area analysis, a PSD increment consumption analysis, an ambient air quality standards impact analysis, and an additional impacts analysis. These analyses are discussed in greater detail in the following paragraphs under specific modelling methodologies. The modelling approach followed EPA and FDEP modelling guidelines for determining compliance with applicable PSD increments and ambient air quality standards. A modelling protocol was prepared by the applicant and submitted to FDEP for review (GRU, 1993a). The FDEP approved the modelling protocol (FDEP, 1993a) prior to commencement of the air quality impact assessment.

6.3 MODEL SELECTION AND OPTIONS

6.3.1 Dispersion Model Selection

The area surrounding the Deerhaven Generating Station has been determined to be a rural area based upon the technique for urban/rural determinations documented in the EPA *Guideline on Air Quality Models (Revised)* (EPA, 1993a) which applies land use criteria. Based upon this determination, the refined ISCST2 dispersion model (Version 93109) was selected for use in the air quality impact analysis used to support the PSD permit application. The ISCST2 model, documented in a user's guide (EPA, 1992), is a referenced EPA dispersion model recommended for use in rural areas, and for application to point, area, and volume sources. The ISCST2 model can predict the maximum (highest) as well as the highest, second-highest concentrations and periods of occurrence for 1-hour, 3-hour, 8-hour, 24-hour, and annual averaging periods at each receptor for each full year of hourly meteorological data used.

6.3.2 Dispersion Model Options

The regulatory default mode for all of the program control parameters was used in the ISCST2 model as approved by FDEP. The ISCST2 model was applied without terrain adjustment data because the area in which the Deerhaven Generating Station is located has very little relief (e.g., a net change in ground level elevation in the range of only 10-20 feet). The ISCST2 model's building downwash options were applied because the stack for the proposed source will be less than GEP stack height.

Because proposed emissions would come from a single stack, emissions impacts for the proposed source with respect to all applicable pollutants were scaled with reference to emissions of one gram per second. The air quality impact assessment for PM assumed that all PM emissions were PM_{10} emissions. This assumption simplified the PM modelling analysis and resulted in a conservative approach to modelling PM_{10} impacts.

6.4 METEOROLOGICAL DATA

The air quality modelling analysis used hourly preprocessed National Weather Service (NWS) surface meteorological data from Gainesville Regional Airport, Florida, and concurrent twice-daily upper air soundings from Tampa (Ruskin), Florida, for the years 1985-1989. The meteorological data were supplied by FDEP in the preprocessed format required by the ISCST2 model. The preprocessed hourly meteorological data file for each year of record used in the analysis contains randomized wind direction, wind speed, ambient temperature, atmospheric stability using the Turner (1970) stability classification scheme, and mixing heights. The anemometer height of 6.7 meters, used in the modelling analysis, was obtained from NWS Local Climatological Data summaries for Gainesville, Florida (NOAA, 1989).

6.5 EMISSIONS INVENTORY

The emissions inventories for the proposed source and fuel scenarios are presented in Tables 6-1 and 6-2. The pollutant emission rates shown in these tables are representative of BACT as demonstrated in Section 4.0.

The proposed source worst-case fuel/load/temperature scenarios were determined by first conducting preliminary modelling. Preliminary modelling runs were conducted using one year of meteorology (1988) at three ambient temperatures (95°F, 75°F, and 20°F) and three CT loads (100%, 80%, and 60%) for both natural gas and distillate fuel oil. In addition, a modelling run was conducted for the CT power augmentation mode at 95°F and 100% load. Thus, there were a total of 19 preliminary modelling runs conducted using the 1988 meteorological data set. A summary of the preliminary modelling runs is presented in Section 7.1.

As a result of these preliminary runs, it was determined that there were four different temperature and load combinations which caused the "worst case" ground-level ambient air quality impacts for the different averaging periods and pollutants. The "worst-case" emission rates, stack parameters and temperature/load information for the averaging times and pollutants are listed in Table 6-3.

The emission rates for hazardous air pollutants were based on distillate fuel oil firing at 100 percent load and 20°F. The emission factors used and the calculated emission rates are contained in Table 6-4.

TABLE 6-1
PROPOSED SOURCE EMISSIONS INVENTORY
NATURAL GAS FIRING

Load (%)	Ambient Temperature (°F)	Hs (m)	Ts (°K)	Vs (m/sec)	Ds (m)	Emission Rates (g/sec)		
						SO_2[1]	PM	NO_x
100	20	15.8	791	48.7	4.3	3.67	0.88	7.31
	59	15.8	805	45.5	4.3	3.32	0.88	6.68
	75	15.8	811	44.0	4.3	3.18	0.88	6.43
	95	15.8	817	42.1	4.3	2.96	0.88	5.93
80	20	15.8	804	40.5	4.3	3.06	0.88	6.18
	59	15.8	823	38.5	4.3	2.80	0.88	5.55
	75	15.8	831	37.5	4.3	2.71	0.88	5.42
	95	15.8	843	36.5	4.3	2.59	0.88	5.17
60	20	15.8	831	35.2	4.3	2.60	0.88	5.17
	59	15.8	851	35.9	4.3	2.40	0.88	4.79
	75	15.8	859	32.8	4.3	2.32	0.88	4.67
	95	15.8	866	32.0	4.3	2.22	0.88	4.41
100+[2]	59	15.8	805	46.6	4.3	3.74	0.88	5.30
	95	15.8	819	43.3	4.3	3.37	0.88	4.79

[1] Based on 10 grains/100 SCF total sulfur in natural gas.
[2] 100+ - Power augmentation mode

CT UTM Coordinates: 365.54 km - East
3,292.72 km - North

Hs - Stack height
Ts - Stack exit temperature
Vs - Stack exit velocity
Ds - Stack diameter

Source: ENSERCH Environmental, 1994

TABLE 6-2
PROPOSED SOURCE EMISSIONS INVENTORY
FUEL OIL FIRING

Load (%)	Ambient Temperature (°F)	Hs (m)	Ts (°K)	Vs (m/sec)	Ds (m)	Emission Rates (g/sec)		
						SO_2 [1]	PM	NO_x
100	20	15.8	786	49.5	4.3	33.54	1.89	29.89
	59	15.8	800	46.2	4.3	30.21	1.89	26.86
	75	15.8	807	44.5	4.3	28.62	1.89	25.35
	95	15.8	815	42.8	4.3	26.95	1.89	23.84
80	20	15.8	811	40.3	4.3	28.24	1.89	24.84
	59	15.8	834	38.8	4.3	25.62	1.89	24.34
	75	15.8	839	37.7	4.3	24.34	1.89	21.44
	95	15.8	843	36.6	4.3	23.05	1.89	20.30
60	20	15.8	849	35.7	4.3	23.88	1.89	20.93
	59	15.8	855	33.9	4.3	21.77	1.89	19.04
	75	15.8	859	33.1	4.3	20.74	1.89	18.16
	95	15.8	862	32.2	4.3	19.70	1.89	17.28

(1) Based on 0.25% sulfur in fuel oil. Future use will be based on 0.05% sulfur in fuel oil.

CT UTM Coordinates: 365.54 km - East
3,292.72 km - North

Hs - Stack height
Ts - Stack exit temperature
Vs - Stack exit velocity
Ds - Stack diameter

Source: ENSERCH Environmental, 1994

TABLE 6-3
EMISSION INFORMATION FOR WORST-CASE AMBIENT IMPACT SCENARIOS

Pollutant	Averaging Period	Worst Case Fuel	Temperature (°F)	CT Load (%)	Stack Parameters				Emission Rate (g/s)
					Ts (°K)	Vs (m/s)	Hs (m)	Ds (m)	
SO_2	Annual	Gas/Fuel Oil[(1)]	20	80	811.33	46.02	15.8	4.3	7.25
	24-hour	Fuel Oil[(2)]	20	80	811.33	46.02	15.8	4.3	28.24
	3-hour	Fuel Oil[(2)]	75	60	858.6	33.53	15.8	4.3	20.74
PM_{10}	Annual	Gas/Fuel Oil	95	60	861.89	32	15.8	4.3	0.62
	24-hour	Fuel Oil	95	60	861.89	32	15.8	4.3	1.89
CO	8-hour	Fuel Oil	20	60	848.56	38.71	15.8	4.3	7.95
	1-hour	Fuel Oil	75	60	848.56	38.71	15.8	4.3	7.31
NO_x	Annual	Gas/Fuel Oil	20	80	811.33	46.02	15.8	4.3	7.61

(1) Based on 0.25% sulfur fuel oil, and natural gas containing 10 grains/100 SCF total sulfur - 2000 hr/yr FOF, 1510 hr/yr NGF, and 390 hr/yr PA.
(2) Based on 0.25% sulfur fuel oil. Future oil use will be on 0.05%S basis and emissions will be lower.
(3) CO was included in the preliminary modelling runs for the monitoring exemption request and significant impact area analyses. It was later determined that CO emissions were below the PSD significant emission rate and need not be included in the modelling.

Ts - Stack temperature
Vs - Exit velocity
Hs - Stack height
Ds - Stack diameter

Source: ENSERCH Environmental, 1994

TABLE 6-4 HAZARDOUS AIR POLLUTANT EMISSION INVENTORY			
Pollutant	**Emission Factor[1] (Lbs/mmBTU)**	**Emission Rates**	
		(Lbs/Hr)	**(g/s)**
Antimony	2.20e-05	2.42e-02	3.05e-03
Arsenic	4.90e-06	5.39e-03	6.80e-04
Beryllium	3.30e-07	3.63e-04	4.58e-05
Cadmium	4.20e-06	4.62e-03	5.83e-04
Chromium	4.70e-05	5.17e-02	6.52e-03
Cobalt	9.10e-06	1.00e-02	1.26e-03
Formaldehyde	(1)	4.50e+00	5.78e-1
Lead	5.80e-05	6.38e-02	8.05e-03
Manganese	3.40e-04	3.74e-01	4.72e-02
Mercury	9.10e-07	1.00e-03	1.26e-04
Nickel	1.20e-03	1.32e+00	1.66e-01
Selenium	5.30e-06	5.83e-03	7.35e-04

(1) Emission factors are from AP-42, Section 3.1, Table 3.1-7, with the exception of formaldehyde which is based on the VOC emission rate of 4.5 lbs/hr. This assumes all VOC emitted during NGFPA is formaldehyde.

Source: ENSERCH Environmental, 1994

6.6 RECEPTOR LOCATIONS

6.6.1 Receptor Grids for Site Vicinity

Ambient concentrations were determined for the significant impact area and monitoring exemption analyses for receptors in a polar grid consisting of 36 radial directions at 10 degree intervals at distances listed below (in kilometers) from the site origin, the new CT:

1.0	3.5	6.0	11.0	16.0
1.5	4.0	7.0	12.0	17.0
2.0	4.5	8.0	13.0	18.0
2.5	5.0	9.0	14.0	19.0
3.0	5.5	10.0	15.0	20.0

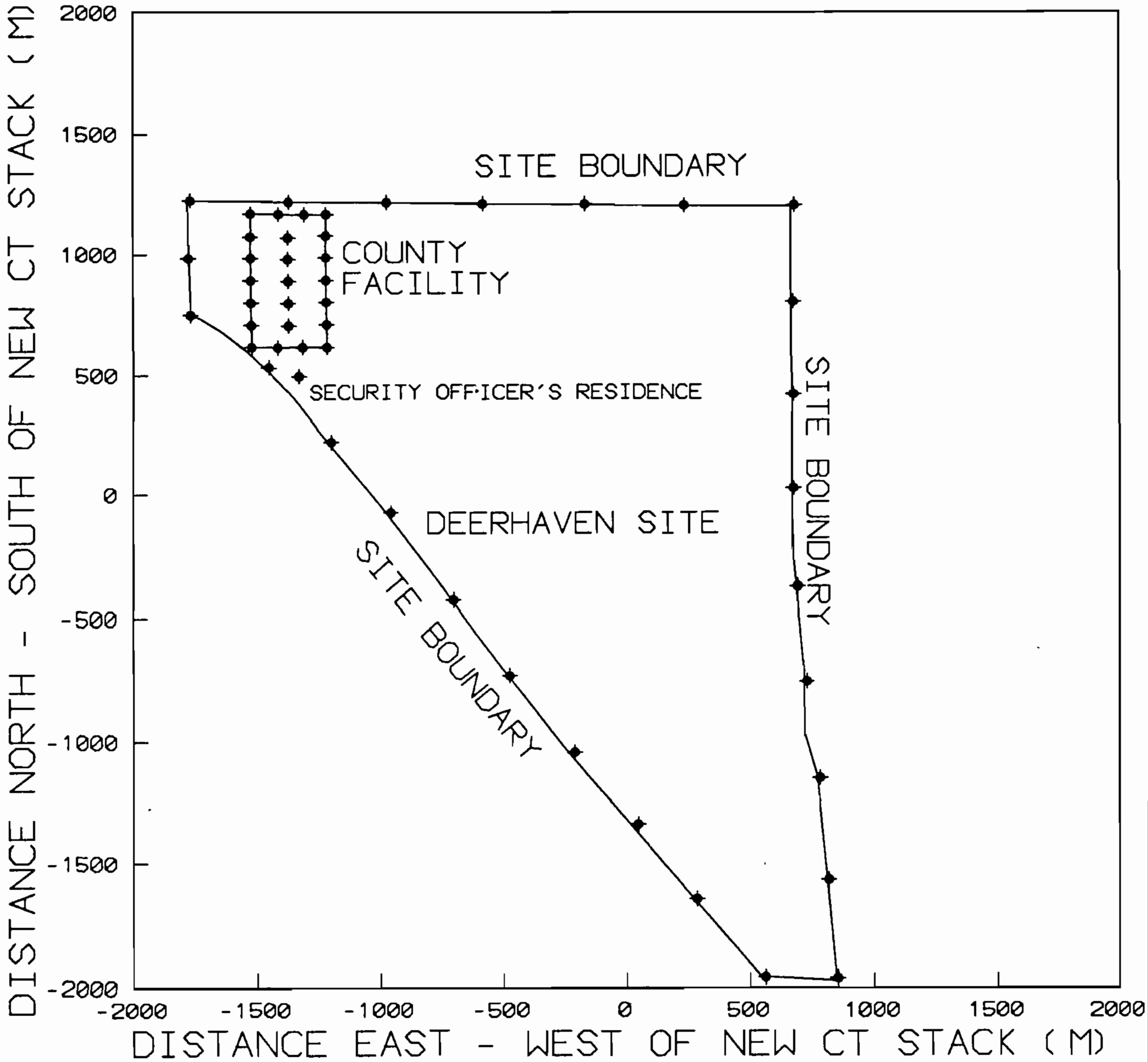
Receptors from these polar grids which fell within the project site boundaries were not included but 26 additional receptors were placed around the site boundary. In addition, receptors were placed around the perimeter of the Alachua County Public Works facility located within the project site boundary and at a security officer's residence which is also located within the site boundary. Figure 6-1 presents the location of the site boundary receptors.

As requested by FDEP, additional receptor rings were added at 250 m intervals, 1 km either side of the receptor ring which contained the highest predicted impact from the preliminary modelling runs which identified the worst case temperature/load combinations. Figures 6-2 through 6-7 depict the locations of these receptors along with the original receptors for various pollutant, averaging time, ambient temperature and CT load combinations.

These more refined receptor grids were used and all five years of meteorological data were run for the "worst case" load and ambient temperature combinations previously described.

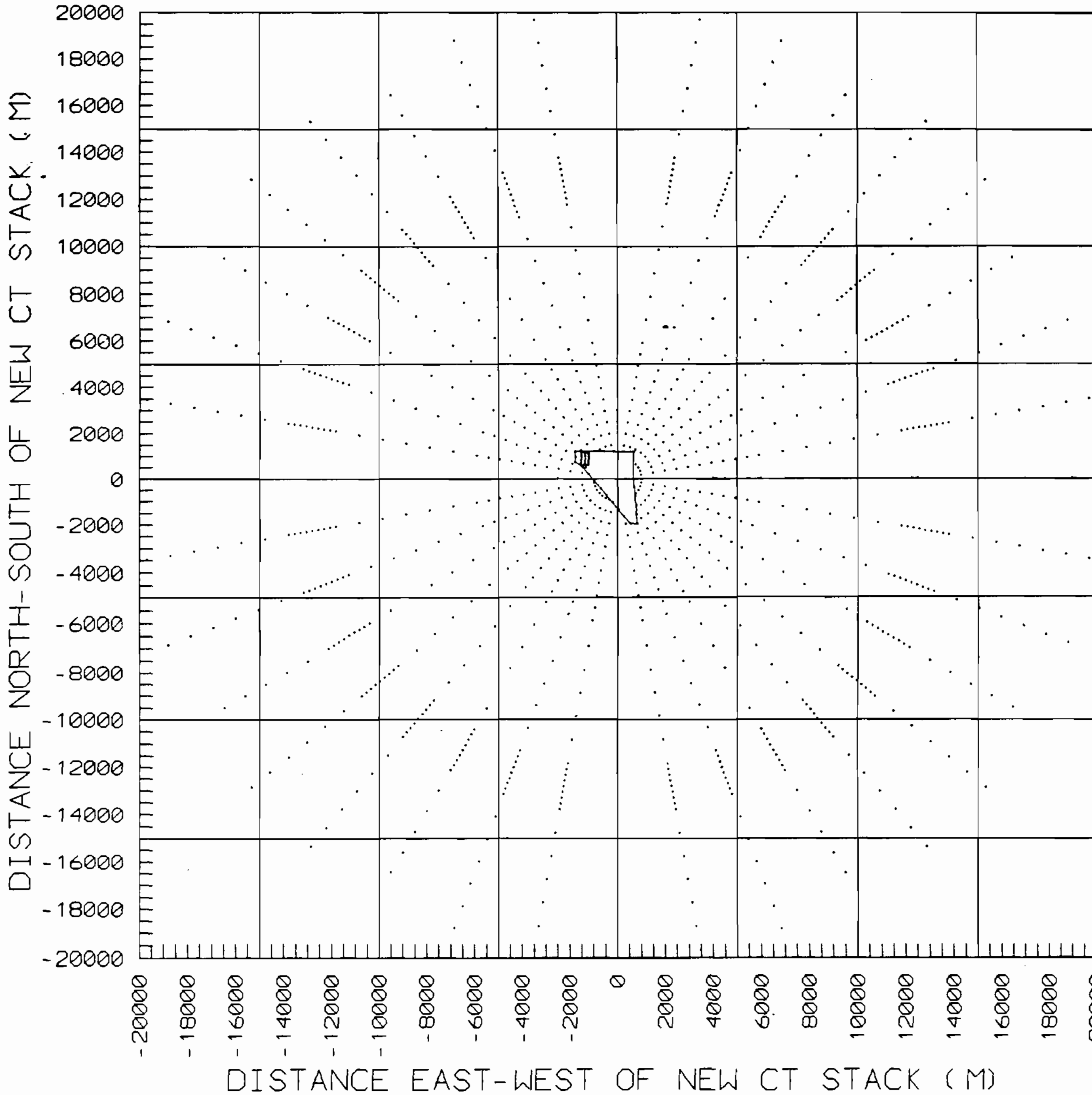
6.6.2 Receptor Grid for Class I PSD Analysis

The modelling for the Chassahowitzka National Wilderness Area analysis used a 13-point receptor grid obtained from FDEP. This grid consists of a series of points located along the boundary of the Class I area. The coordinates of these points are listed in Table 6-5. The modelling for the Okefenokee PSD Class I Area analysis used a 10-point receptor grid also



Source: ENSERCH Environmental, 1994

GRU	ISCST2 RECEPTOR LOCATIONS Site Boundary, County Facility and Security Officer's Residence	FIGURE 6-1

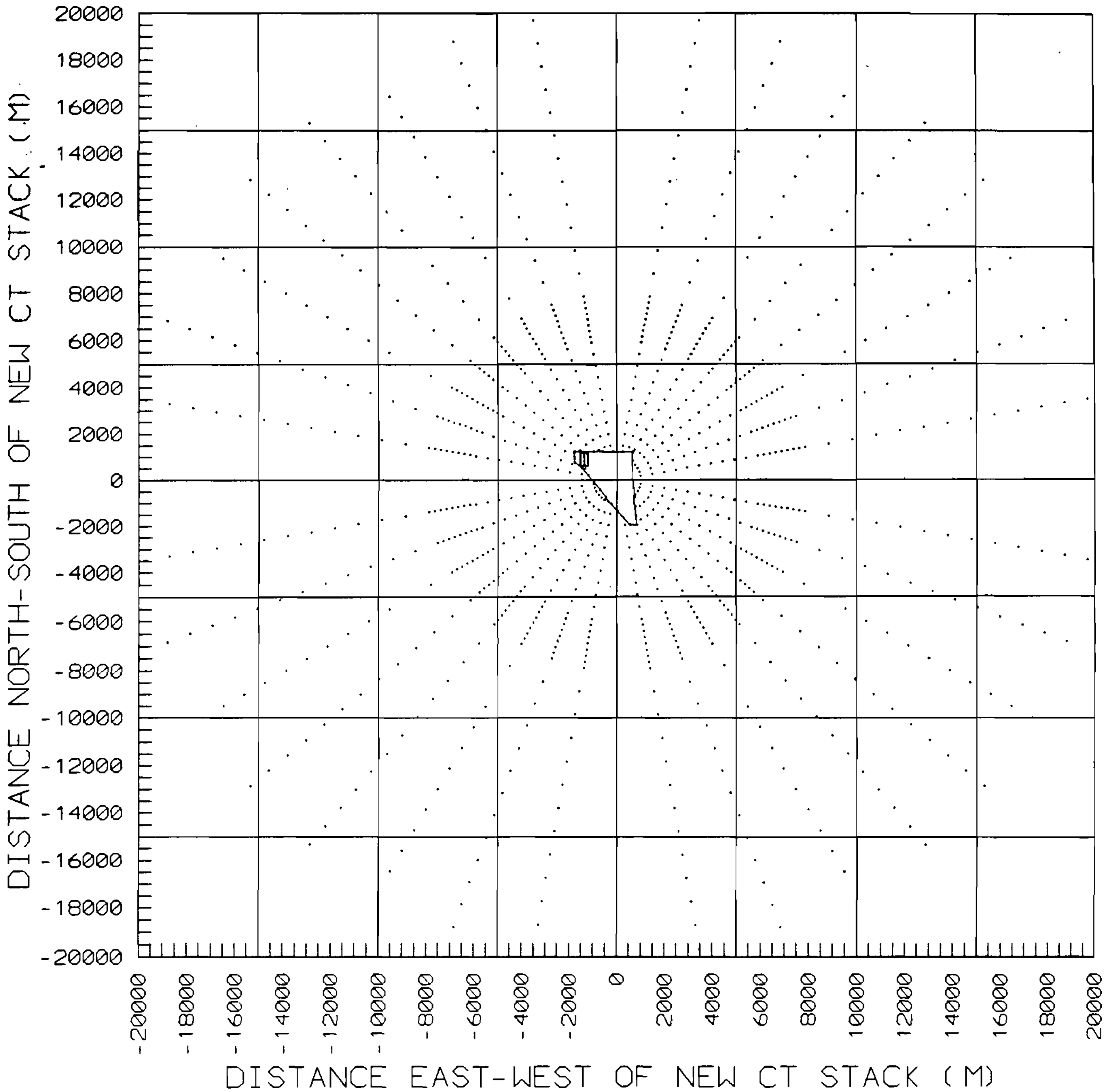


Source: ENSERCH Environmental, 1994

GRU

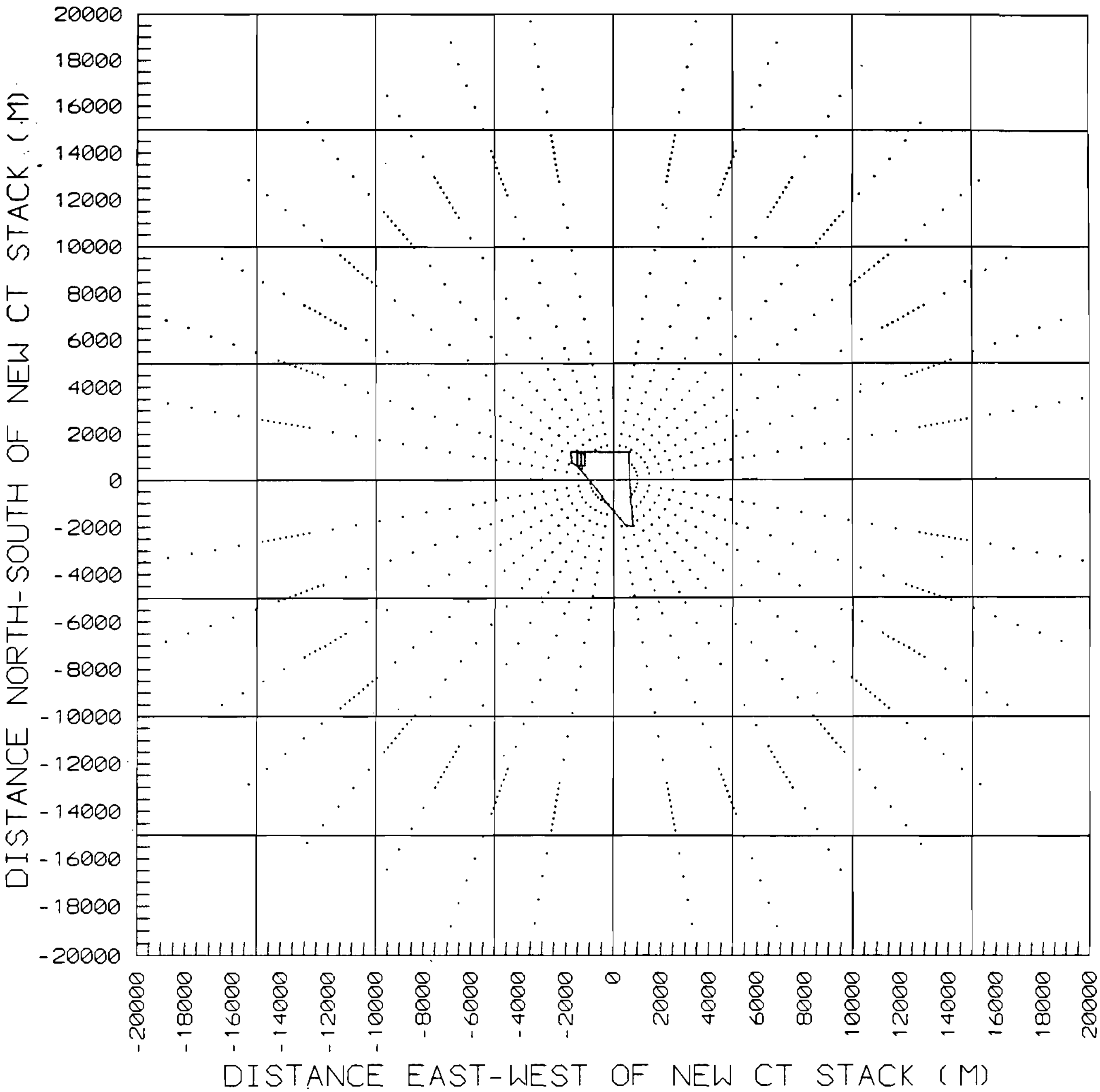
ISCST2 RECEPTOR LOCATIONS
SO_2 24-Hour - 20°F 80% Load

FIGURE 6-2



Source: ENSERCH Environmental, 1994

GRU	ISCST2 RECEPTOR LOCATIONS SO_2 and NO_X Annual - 20°F 80% Load	FIGURE 6-3

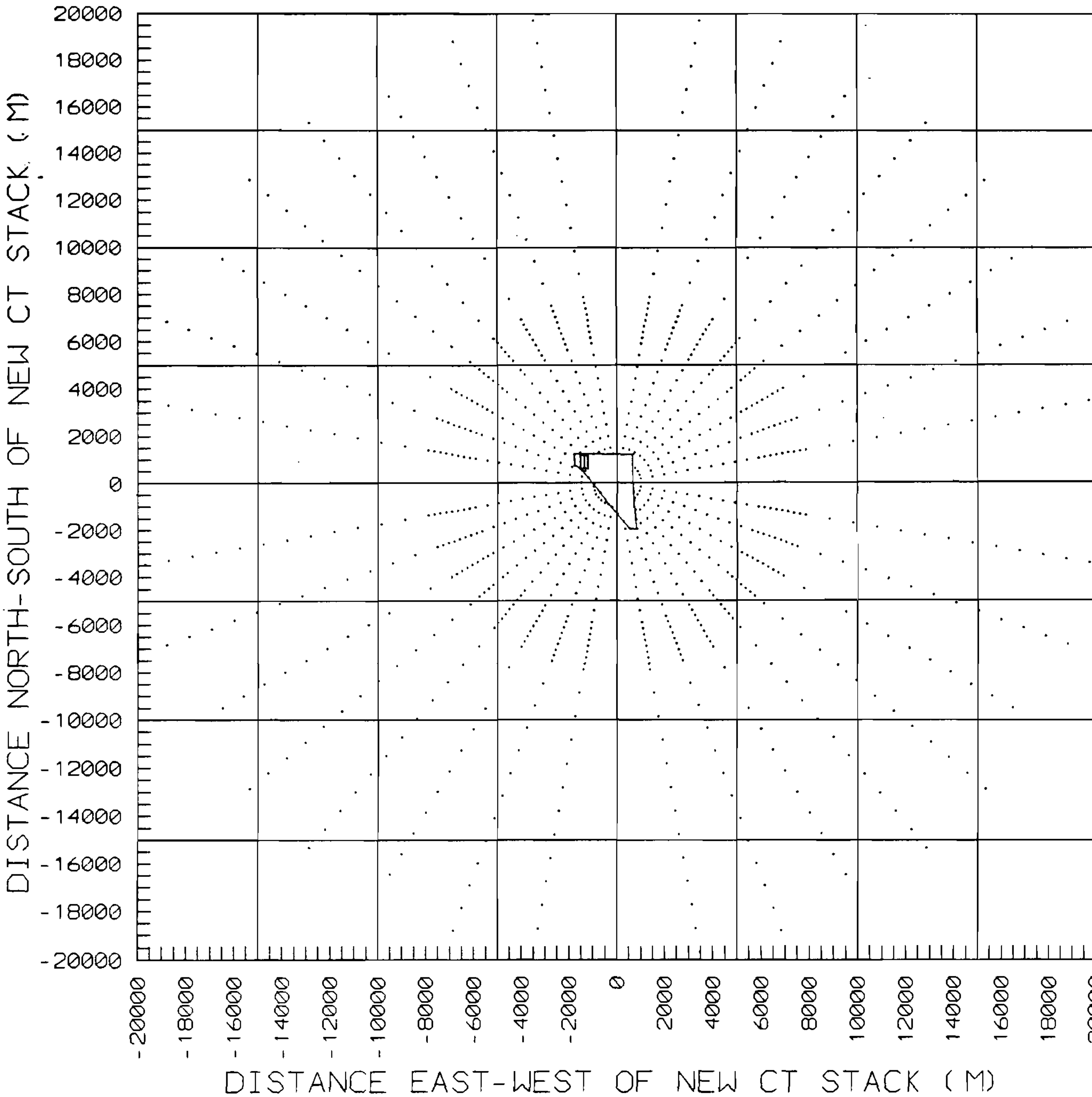


Source: ENSERCH Environmental, 1994

GRU

ISCST2 RECEPTOR LOCATIONS
PM_{10} 24-Hour - 95^{0}F 60% Load

FIGURE
6-4

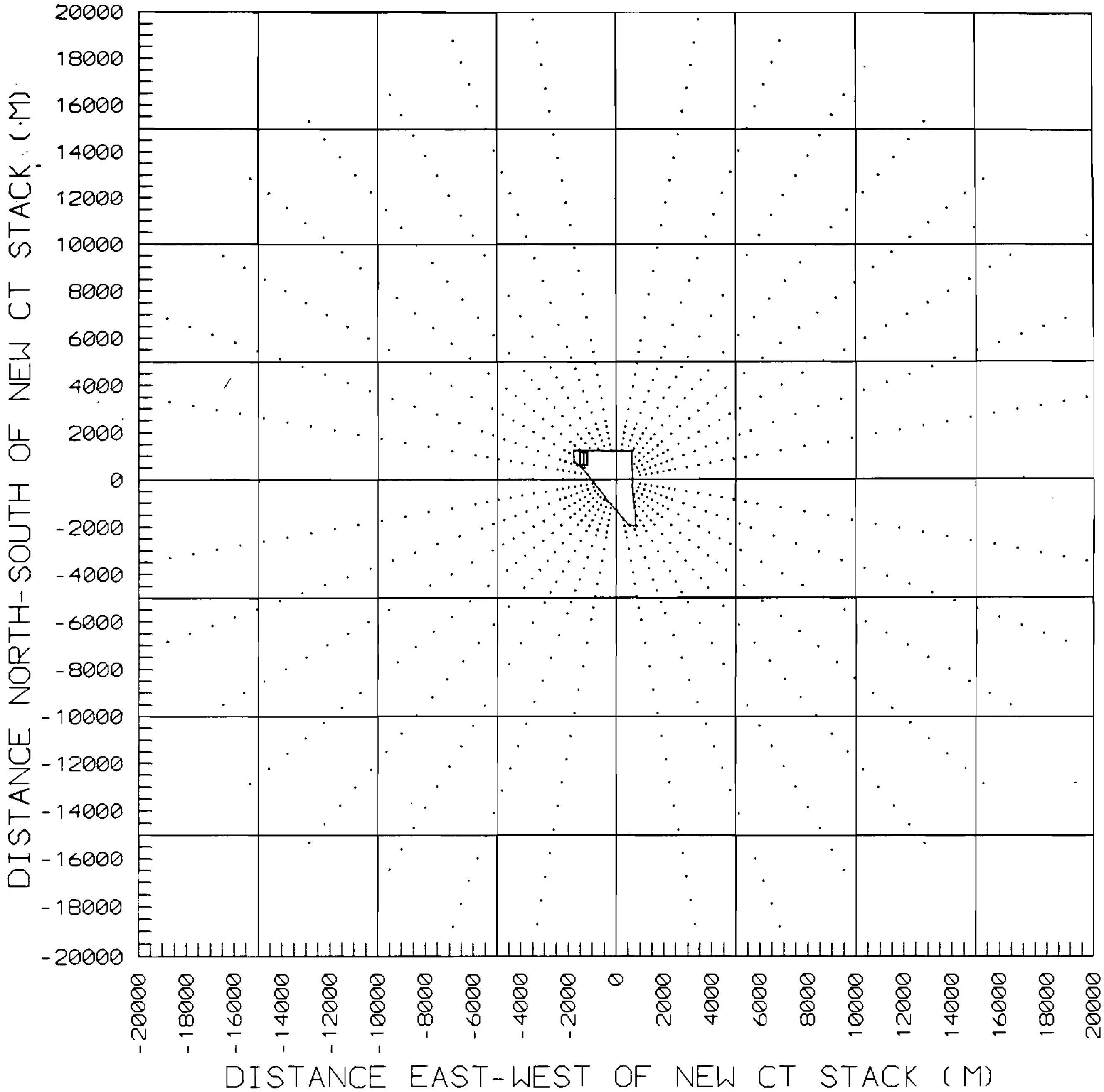


Source: ENSERCH Environmental, 1994

GRU

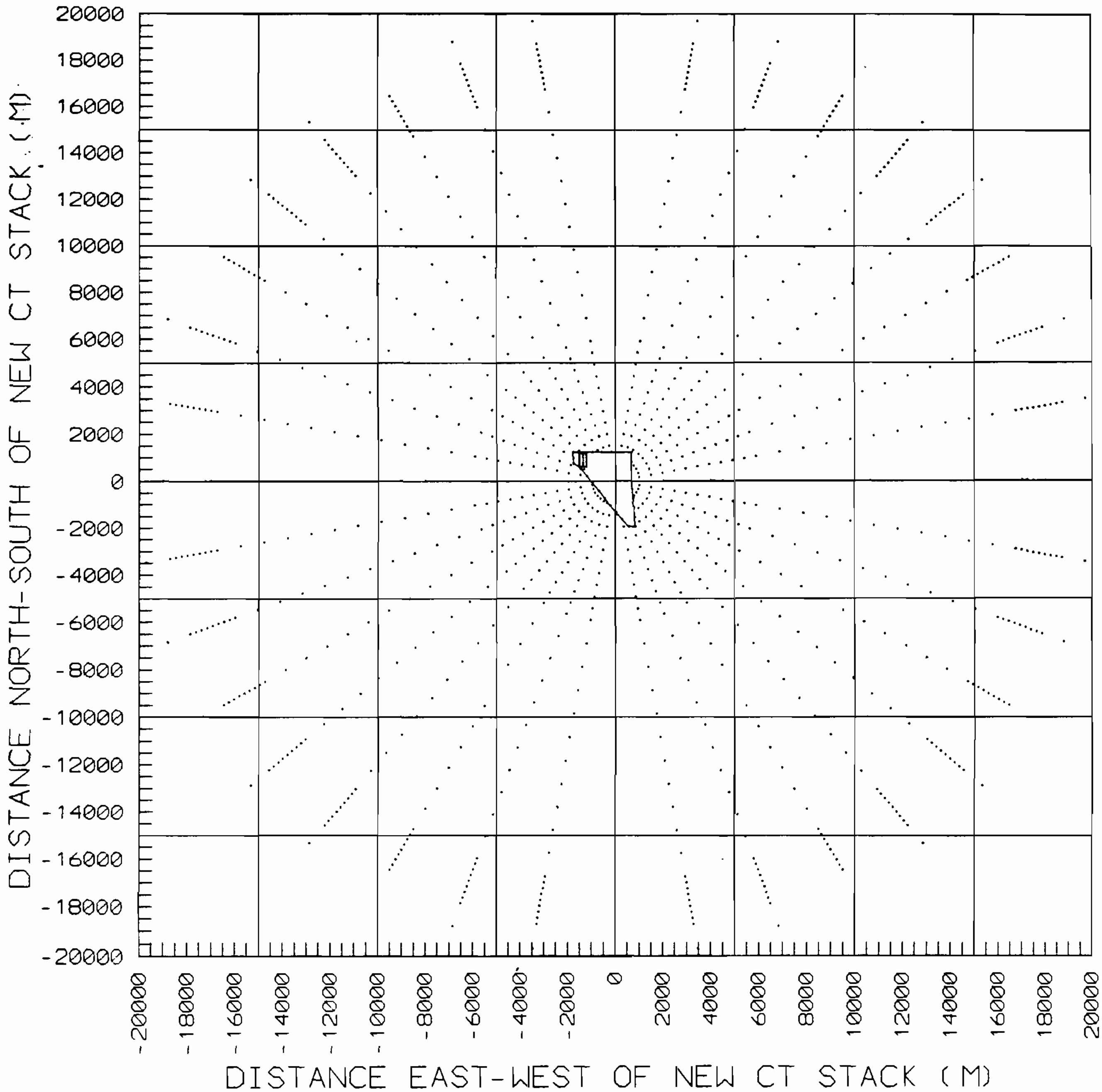
ISCST2 RECEPTOR LOCATIONS
PM_{10} Annual - 95°F 60% Load

FIGURE 6-5



Source: ENSERCH Environmental, 1994

GRU	**ISCST2 RECEPTOR LOCATIONS** **SO_2 3-Hour and CO 1 Hour - 75°F 60% Load**	**FIGURE** **6-6**



Source: ENSERCH Environmental, 1994

GRU

ISCST2 RECEPTOR LOCATIONS
CO 8 - Hour - 20°F 60% Load

FIGURE
6-7

TABLE 6-5
RECEPTOR GRID FOR CHASSAHOWITZKA PSD CLASS I AREA

Point	UTM Coordinates		Distance from Deerhaven Generating Station[1]		
	East (km)	North (km)	ΔX (km)	ΔY (km)	Distance (km)
1	340.3	3,165.7	25.24	127.02	129.5
2	340.3	3,167.7	25.24	125.02	127.5
3	340.3	3,169.8	25.24	122.92	125.5
4	340.7	3,171.9	24.84	120.82	123.3
5	342.0	3,174.0	23.54	118.72	121.0
6	343.0	3,176.2	22.54	116.52	118.7
7	343.7	3,178.3	21.84	114.42	116.5
8	342.4	3,180.6	23.14	112.12	114.5
9	341.1	3,183.4	24.44	109.32	112.0
10	339.0	3,183.4	26.54	109.32	112.5
11	336.5	3,183.4	29.04	109.32	113.1
12	334.0	3,183.4	31.54	109.32	113.8
13	331.5	3,183.4	34.04	109.32	114.5

[1] Location of "zero point" for Deerhaven Generating Station is 365.540 km east, 3,292.720 km north.

Note: The general location of the PSD Class I Chassahowitzka Wilderness Area is depicted in Figure 1-1.

obtained from FDEP consisting of points along the southern and eastern boundary of the Okefenokee. The coordinates of these points are listed in Table 6-6.

6.7 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with structures planned for and existing at the Deerhaven Generating Station, the 15.8 meter stack for the proposed CT unit will be less than the calculated GEP stack height (38 meters). Therefore, the potential for building downwash to occur was considered in the modelling analysis.

The procedures used for addressing the effects of building downwash are those recommended in the *User's Guide For the Industrial Source Complex (ISC2) Dispersion Models* (EPA, 1992). The building height and effective width are input to the model, which uses these parameters to calculate downwash. For short stacks (i.e., physical stack height is less than $H_b + 0.5\ L_b$, where H_b is the building height and L_b is the lesser of the building height or projected width), the Schulman and Scire (1980) method is used. For cases where the physical stack is greater than $H_b + 0.5\ L_b$ but less than GEP, the Huber-Snyder (1976) method is used. Direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10-degree sector.

In the case of the proposed CT unit, the turbine structure is the dominant building of influence. Utilizing the input stack height and direction specific building dimensions, the ISC2 model selects the appropriate method to calculate building downwash based on the $\mathrm{H_b} + 0.5\ \mathrm{L_b}$ criteria.

Cavity calculations were not performed since all of the nearby structures are well over three times the height of the nearby structures from the site boundary, and no off-site influences are expected.

TABLE 6-6
RECEPTOR GRID FOR OKEFENOKEE PSD CLASS I AREA

Point	UTM Coordinates		Distance from Deerhaven Generating Station[1]		
	East (km)	North (km)	ΔX (km)	ΔY (km)	Distance (km)
1	391.0	3,471.0	25.46	124.28	126.9
2	390.0	3,410.0	24.46	117.28	119.8
3	392.0	3,400.0	26.46	107.28	110.5
4	390.0	3,395.0	24.46	102.28	105.2
5	391.0	3,390.0	25.46	97.28	100.6
6	390.0	3,384.0	24.46	91.28	94.5
7	383.0	3,384.0	17.46	91.28	92.9
8	378.0	3,382.0	12.46	89.28	90.1
9	374.0	3,383.0	8.46	90.28	90.7
10	370.0	3,383.0	4.46	90.28	90.4

[1] Location of "zero point" for Deerhaven Generating Station is 365.540 km east, 3,292.720 km north.

Note: The general location of the PSD Class I Okefenokee Area is depicted in Figure 1-1.

7.0 AIR QUALITY IMPACT ANALYSIS RESULTS

This section summarizes the results of the modelling analyses conducted as described in Section 6.0. It is organized into sections dealing with the worst-case operation, modelled impacts versus monitoring significance levels, significant impact areas, impacts of the project by itself, Class I area impacts, and predicted concentrations of hazardous air pollutants (HAPS) versus FDEP's draft "no threat" levels (FDEP, 1992a).

7.1 WORST-CASE OPERATION ANALYSIS

As indicated in Section 6.5, the proposed CT facility was evaluated for both the primary fuel, natural gas, and the back-up fuel, distillate fuel oil, to determine the worst-case, ground-level ambient air quality impacts. Since the emissions on distillate fuel oil are higher for the criteria pollutants than for natural gas, the analysis of short-term impacts focused on the fuel oil case, at the ambient temperatures and loads which provided the highest modelled impacts for each pollutant and averaging period. The specific loads and ambient temperatures which produce the worst-case impacts are highlighted in Table 7-1, which provides the results of the preliminary modelling analyses for applicable short-term and annual averages for SO_2, NO_2, CO and PM_{10}.

7.2 IMPACTS VERSUS MONITORING SIGNIFICANCE LEVELS FOR APPLICABLE SHORT-TERM AND ANNUAL AVERAGES FOR SO_2, NO_x, CO AND PM_{10}

Each of the worst-case scenarios were modelled using five years of meteorological data. The results of modelling the worst-case operating scenarios were compared to the EPA monitoring significance values. The comparison indicated that none of the criteria pollutants exceeded the monitoring significance values. A monitoring exemption request (GRU, 1993) was submitted to FDEP and approved (FDEP, 1994) based on the five year analysis using preliminary emissions data and receptor grids. The preliminary analysis has been revised based on the final emission rates and the slightly revised receptor grids presented in Sections 6.5 and 6.6.1, respectively, and the results are summarized in Table 7-2.

TABLE 7-1
PRELIMINARY MODELLING RESULTS USING 1988 METEOROLOGICAL DATA

Fuel	CT Load (%)	Temp (°F)	Maximum NO_x ($\mu g/m^3$) Annual	Maximum SO_2 ($\mu g/m^3$)[1]			Maximum CO[2] ($\mu g/m^3$)		Maximum PM_{10} ($\mu g/m^3$)	
				3-Hour	24-Hour	Annual[3]	1-Hour	8-Hour	24-Hour	Annual[2]
Natural Gas	100	95	0.015	0.000	0.000	0.000	1.425	0.294	0.0355	0.0023
Natural Gas	100	75	0.015	0.000	0.000	0.000	1.402	0.306	0.0342	0.0022
Natural Gas	100	20	0.015	0.000	0.000	0.000	1.564	0.334	0.0313	0.0019
Natural Gas	80	95	0.015	0.000	0.000	0.000	1.173	0.262	0.0430	0.0026
Natural Gas	80	75	0.016	0.000	0.000	0.000	1.287	0.281	0.0424	0.0026
Natural Gas	80	20	0.016	0.000	0.000	0.000	1.433	0.300	0.0373	0.0024
Natural Gas	60	95	0.015	0.000	0.000	0.000	1.958	0.437	0.0460	0.0030
Natural Gas	60	75	0.016	0.000	0.000	0.000	1.155	0.253	0.0471	0.0030
Natural Gas	60	20	0.018	0.000	0.000	0.000	1.341	0.309	0.0477	0.0031
Power Aug.	100	95	0.033	0.000	0.000	0.000	1.728	0.378	0.0346	0.0022
Fuel Oil	100	95	0.109	7.175	1.927	0.122	2.799	0.585	0.0738	0.0047
Fuel Oil	100	75	0.112	7.549	1.985	0.125	2.802	0.611	0.0718	0.0045
Fuel Oil	100	20	0.114	8.718	2.121	0.128	2.924	0.679	0.0652	0.0039
Fuel Oil	80	95	0.110	7.091	2.020	0.124	2.384	0.531	0.0905	0.0056
Fuel Oil	80	75	0.113	6.636	2.083	0.127	2.454	0.532	0.0887	0.0054
Fuel Oil	80	20	0.122	7.616	2.150	0.138	2.750	0.576	0.0789	0.0051
Fuel Oil	60	95	0.107	8.931	1.882	0.122	3.159	0.702	0.0985	0.0064
Fuel Oil	60	75	0.109	9.307	1.968	0.124	3.238	0.701	0.0984	0.0062
Fuel Oil	60	20	0.116	7.385	2.134	0.132	3.095	0.705	0.0924	0.0057

(1) Preliminary runs based on 0.46%S in fuel oil and negligible amounts in natural gas.
(2) Preliminary runs included CO. It was later determined that CO would not be emitted in PSD significant quantities.
(3) Preliminary runs based on 8,760 hours/year operation.

Note: Worst-case, ground-level ambient impact scenarios are highlighted.

Source: ENSERCH Environmental, 1994

TABLE 7-2
MODELLING RESULTS FOR MONITORING EXEMPTION[1]

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Monitoring Significance Level ($\mu g/m^3$)	Monitoring Required
SO_2[2]	24-hr	1.5	13	No
PM	24-hr	0.1	10	No
NO_x	Annual	0.03	14	No
CO	8-hr	1.0	575	No
O_3	VOC (Emissions Less than 100 TPY)			No
Pb	Quarter	.0000024 (Annual) .000045 (24-hr)	0.1	No
Be	24-hr	.000012	0.001	No
Hg	24-hr	.000015	0.25	No
Fluorides	24-hr	Nil	0.25	No

(1) Results differ slightly from those presented in the Monitoring Exemption Request (GRU 1993) due to the use of final emissions information and updated receptor grids. Currently predicted impacts are the same or lower than those presented in the monitoring exemption request.
(2) Based on 0.25% S in fuel oil.

Source: ENSERCH Environmental, 1994

7.3 SIGNIFICANT IMPACT AREA ANALYSIS

Once the worst-case operating scenarios were defined and the need for monitoring determined, the next step in the analysis was to determine the significant impact area for each pollutant with an associated PSD increment or AAQS. The significant impact area is defined in the *EPA New Source Review Workshop Manual* (EPA, 1990a) as the circular area whose radius is equal to the greatest distance from the proposed source to which modelling shows that the proposed source will have a significant impact, based upon EPA-defined significance values which are pollutant specific (see Ch.17-212.200(63) F.A.C.). The significant impact areas thus define the distances beyond which the impacts from the proposed source will be insignificant and need not be analyzed in conjunction with existing sources. The results of the significant impact area analyses are presented in Table 7-3. The receptor grids used were described in Section 6.6.1, and maximum concentrations for each averaging period for all five years of meteorological data are provided. As indicated in Table 7-3, none of the pollutants were predicted to have significant off-site impacts. Thus, no further air quality analysis is required for any of the criteria pollutants (i.e. no modelling involving existing sources is required).

7.4 SUMMARY OF IMPACTS — PROPOSED SOURCE ONLY

Table 7-2 provides a summary of maximum predicted impacts due to the proposed source alone. However, the maximum short-term values are based on highest predicted concentrations and are not relevant for comparison with PSD increments and AAQSs which allow one short-term exceedance per year. A summary of maximum off-site impacts using highest annual and highest, second-highest short-term concentrations for the proposed source alone is presented in Table 7-4. As indicated in Table 7-4, maximum off-site impacts for all pollutants are well below the allowable PSD increments, NAAQSs, and FAAQs.

7.5 IMPACTS ON CLASS I AREAS

The potential impacts of the proposed CT on the nearest Class I PSD areas were evaluated in accordance with the procedures outlined in Section 6.6. For this analysis worst-case emissions (100 percent load at 20°F on distillate fuel oil) for short-term impacts were assumed. The ISCST2 model was run with all five years of meteorological data to determine whether the impacts would exceed the PSD Class I significance criteria suggested by the National Park Service (NPS). This modelling was conducted for the Okefenokee National

TABLE 7-3
SUMMARY OF WORST-CASE OFF-SITE IMPACTS
VERSUS CLASS II PSD SIGNIFICANCE VALUES

Pollutant	Averaging Time	Emission Rate (g/s)	Ambient Temperature (°F)	CT Load (%)	Year	Normalized[1] Impact ($\mu g/m^3$)	Maximum Impact ($\mu g/m^3$)	Class II Significance Value ($\mu g/m^3$)
SO_2[2]	Annual	7.25	20	80	85	.00257	0.01863	1
					86	.00227	0.01646	
					87	.00239	0.01733	
					88	.00257	0.01863	
					89	.00246	0.01784	
	24-Hour	28.24	20	80	85	.03910	1.1042	5
					86	.03405	0.9616	
					87	.03986	1.1256	
					88	.04025	1.1367	
					89	.05223	1.4750	
	3-Hour	20.74	75	60	85	.20018	4.1517	25
					86	.18534	3.8440	
					87	.19481	4.0404	
					88	.17011	3.5281	
					89	.18529	3.8429	
PM_{10}	Annual	0.62	95	60	85	.00309	0.00192	1
					86	.00276	0.00171	
					87	.00286	0.00177	
					88	.00331	0.00205	
					89	.00313	0.00194	
	24-Hour	1.89	95	60	85	.04638	0.08766	5
					86	.03973	0.07509	
					87	.04964	0.09382	
					88	.05199	0.09826	
					89	.06108	0.11544	

TABLE 7-3
SUMMARY OF WORST-CASE OFF-SITE IMPACTS
VERSUS CLASS II PSD SIGNIFICANCE VALUES

Pollutant	Averaging Time	Emission Rate (g/s)	Ambient Temperature (°F)	CT Load (%)	Year	Normalized[1] Impact (μg/m³)	Maximum Impact (μg/m³)	Class II Significance Value (μg/m³)
PM_{10}	8-Hour	1.89	95	60	85	.10987	0.20765	N/A
					86	.09372	0.17713	
					87	.12205	0.23067	
					88	.09546	0.18046	
					89	.13702	0.25897	
CO	8-Hour	7.95	20	60	85	.10005	0.79540	500
					86	.08489	0.67488	
					87	.12073	0.95980	
					88	.08630	0.68609	
					89	.12577	0.99987	
	1-Hour	7.31	75	60	85	.45575	3.33153	2000
					86	.46655	3.41048	
					87	.48079	3.51457	
					88	.42571	3.11194	
					89	.41337	3.02713	
NO_2	Annual	7.61	20	80	85	.00257	0.01956	1
					86	.00227	0.01727	
					87	.00239	0.01819	
					88	.00257	0.01956	
					89	.00246	0.01872	

(1) Normalized impacts are taken directly from the modelling runs and are based on an emission rate of 1 g/s. Maximum impacts are obtained by multiplying the actual emission rate times the normalized impacts.

(2) Based on 0.25% sulfur in fuel and 10 grains/100 SCF in natural gas.

(3) Although no significance value is given for PM_{10} for this averaging period, these results are presented to support the HAP analysis in Section 7.6.

Notes: Maximum impacts are highest values. Short-term emission rates are for fuel oil and are based on specified load and temperature. Annual emission rates are based on 3,900 hours/year (FOF 2,000 hours/year + NGF 1,510 hours/year + NGFPA 390 hours/year). At the specified temperature and load for fuel oil, 20°F and 100% load for natural gas and ISO conditions and 100% load for power augmentation.

Source: ENSERCH Environmental, 1994

TABLE 7-4

SUMMARY OF MAXIMUM OFF-SITE IMPACT CONCENTRATIONS

Pollutant	Averaging Period	Maximum [1] Predicted Concentration ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)	FAAQS ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
Carbon Monoxide	1-Hour	3.2	N/A	40,000	40,000
	8-Hour	0.7	N/A	10,000	10,000
Nitrogen Dioxide	Annual	0.02	25	100	100
Sulfur Dioxide[2]	3-Hour	3.7	512	1,300	1,300
	24-Hour	1.0	91	260	365
	Annual	0.02	20	60	80
Particulate Matter (PM_{10} or TSP) [3]	24-Hour	0.09	37 (30)	150	150
	Annual	0.002	19 (17)	50	50
Sulfuric Acid Mist[2]	24-Hour	0.11	N/A	N/A	N/A

[1] Short-term values are highest, second-highest values for this analysis except for sulfuric acid.

[2] Based on 0.25% sulfur in fuel and 10 grains/100 SCF in natural gas. Future fuel oil will be 0.05% sulfur maximum.

[3] The allowable PSD increment is currently evaluated for TSP whereas the AAQS compliance is evaluated for PM_{10}. As a conservative approach, all project emissions of particulate matter were assumed to be in the form of PM_{10}. The PM_{10} PSD increments which will become effective on 6/3/94 are shown in parentheses.

N/A = Not applicable
FAAQS = Florida Ambient Air Quality Standards
NAAQS = National Ambient Air Quality Standards

Source: ENSERCH Environmental, 1994
Ch.17-272.300 FAC
Ch.17-272.500 FAC
40 CFR 50
Federal Register Vol. 58 No. 105, June 3, 1993, p. 31621-31638

Wilderness Area and the Chassahowitzka National Wilderness Area, the nearest two Class I areas.

The results of this analysis are presented in Table 7-5. As indicated, the maximum predicted impacts of PM_{10} and NO_2 are below the NPS significance values, even using the overly conservative assumption of 3,900 hours per year of operation on distillate fuel oil. Based on 2,000 hours per year of fuel oil with 0.25% sulfur by weight, (the existing fuel supply), the short-term SO_2 impacts are above the NPS significance values. However, as indicated in Section 4, a large percentage of the existing fuel oil supply will be consumed during the initial start-up and testing; subsequently, only very low sulfur fuel oil will be used. The maximum predicted impacts using the very low sulfur fuel oil fall below the NPS significance values, as indicated in Table 7-5. This indicates that the impacts of the proposed project on the Class I areas will be "insignificant" when firing natural gas or very low sulfur fuel oil and no further Class I increment consumption assessments are required.

7.6 HAZARDOUS AIR POLLUTANTS (AIR TOXICS ANALYSIS)

This HAPS analysis follows the FDEP's draft air toxics guidelines as revised by the November 29, 1993 guidance memorandum from Howard Rhodes (Appendix D). Pursuant to this memorandum, the air toxics (HAPS) are limited to those pollutants regulated under Section 112 of the Clean Air Act as amended by Title III of the 1990 amendments. For this project, the applicable HAPS emitted by the combustion turbine are listed in Table 6-4.

For each HAP, the maximum emission rates were based on CT operation at full load and an ambient temperature of 20°F. Maximum CT 8-hour, 24-hour and annual impacts were determined based on a normalized emission rate (1 gram/second) and the ISCST2 dispersion model. Worst-case normalized impacts were obtained from Table 7-3. These were multiplied by HAP emission rates at full load rather than at the partial loads in Table 7-3. This approach resulted in a very conservative analysis.

In the case of formaldehyde, the maximum emission rate was based on the maximum VOC emission rate when firing natural gas. This maximum rate occurred during the power augmentation mode at ISO conditions. The assumption that all the VOC emissions are formaldehyde is conservative based on the Profile 0007, Natural Gas Turbine (EPA, 1990b). In the case of the trace metals, the maximum emission rates were based on fuel oil firing and the AP-42 emission factors in Section 3.1, Table 3.1-7 (EPA, 1993).

TABLE 7-5
SUMMARY OF MAXIMUM CLASS I AREA IMPACTS
AT 20°F 100% LOAD ON FUEL OIL

Pollutant	Emissions (g/s)	Averaging Period	Maximum Concentration ($\mu g/m^3$)		EPA (Virginia) Significance Values ($\mu g/m^3$)	NPS Significance Values ($\mu g/m^3$)
			Chassahowitzka	Okefenokee		
Based on 3,900 Hours/Year (.445 of Year) of .25% S Fuel Oil:						
SO_2	14.9 33.6 33.6	Annual 24 3	0.00522 0.31954 1.52443	0.00552 0.34238 1.34299	0.1 0.275 1.23	.025 .07 .48
PM_{10}	0.85 1.9	Annual 24	0.00030 0.01807	0.00030 0.01936	.27 1.35	.08 .33
NO_2	13.3	Annual	0.00466	0.00466	0.1	.025
Based on 2,000 Hours/Year (.228 of Year) of .25% S FOF, 390 hrs/yr of NGFPA and 1,510 hrs/yr of NGF:						
SO_2	15.7 33.6 33.6	Annual 24 3	0.00550 0.31954 1.52443	0.00550 0.34238 1.34299	0.1 0.275 1.23	.025 .07 .48
Based on 2,000 Hours/Year (.228 of Year) of .05% S FOF, 390 hrs/yr of NGFPA and 1,510 hrs/yr of NGF:						
SO_2	5.2 6.68 6.68	Annual 24 3	0.00182 0.06353 0.30307	0.00182 0.06807 0.26700	0.1 0.275 1.23	.025 .07 .48

Note: Annual emission rates are scaled based on 3,900 or 2,000 hours per year of operation.
SO_2 emission rates based on current fuel oil (0.25% S) and future fuel oil (0.05% S) and natural gas containing 10 grains/100 SCF of total sulfur.

Source: ENSERCH Environmental, 1994

The maximum HAP impacts are summarized in Table 7-6. In all cases, the estimated impacts are below the FDEP's draft no threat levels.

TABLE 7-6
SUMMARY OF HAZARDOUS AIR POLLUTANT IMPACTS

Pollutant	Emission Rate (g/s)[1]	FDEP Draft No Threat Levels			Predicted HAP Impacts			Acceptable (Yes/No)
		8-Hour	24-Hour	Annual	8-Hour	24-Hour	Annual	
Formaldehyde[2]	5.68e-01	1.20e+01	2.88e+00	7.70e-02	7.78e-02	3.47e-02	7.92e-04	Yes
Antimony	3.05e-03	5.00e+00	1.20e+01	3.00e-01	4.18e-04	1.86e-04	2.18e-06	Yes
Arsenic	6.80e-04	2.00e+00	4.80e-01	2.30e-04	9.32e-05	4.15e-05	4.86e-07	Yes
Beryllium	4.58e-05	2.00e-02	4.80e-03	4.20e-04	6.28e-06	2.80e-06	3.27e-08	Yes
Cadmium	5.83e-04	5.00e-01	1.20e-01	5.60e-04	7.99e-05	3.56e-05	4.17e-07	Yes
Chromium	6.52e-03	5.00e-01	1.20e-01	8.30e-05	8.93e-04	3.98e-04	4.66e-06	Yes
Cobalt	1.26e-03	5.00e-01	1.20e-01	N/A	1.73e-04	7.70e-05	9.00e-07	Yes
Lead	8.05e-03	5.00e-01	1.20e-01	9.00e-02	1.10e-03	4.92e-04	5.75e-05	Yes
Manganese	4.72e-02	5.00e+01	1.20e+01	4.00e-01	6.47e-03	2.88e-03	3.37e-08	Yes
Mercury	1.26e-04	1.00e-01	2.40e-02	3.00e-01	1.73e-05	7.70e-06	9.00e-04	Yes
Nickel	1.66e-01	1.00e+00	2.40e-01	N/A	2.27e-02	1.01e-02	1.19e-07	Yes
Selenium	7.35e-04	2.00e+00	4.80e-01	N/A	1.01e-05	4.49e-05	5.25e-07	Yes

(1) Annual emission rates scaled to 3,900/8,760 for formaldehyde and to 2,000/8,760 for all others.
(2) Based on VOC emission rate for natural gas firing. Assumes all VOC is formaldehyde.

Normalized Impacts (i.e., impacts based on emissions of 1 g/s): Maximum 8-hour - 0.13702 $\mu g/m^3$
Maximum 24-hour - 0.06108 $\mu g/m^3$
Annual - 0.00313 $\mu g/m^3$

Source: ENSERCH Environmental, 1994

8.0 ADDITIONAL IMPACTS ANALYSIS

8.1 INTRODUCTION

The PSD guidelines indicate that, in addition to demonstrating that the proposed source will neither cause nor contribute to violations of the applicable PSD increments and AAQS, an additional impacts analysis must be conducted for those pollutants subject to PSD review. As indicated in Table 3-4, for this project these pollutants are NO_X, SO_2, PM, and sulfuric acid mist. The additional impacts analysis addresses air quality impacts due to growth induced by the project and air quality impacts on soils, vegetation, and visibility. Furthermore, consideration is given to the HAPS (trace metals) that will be emitted by the project in small quantities rather than restricting the analyses to those pollutants subject to PSD review.

The visibility, vegetation, and soils additional impacts analysis focuses on nearby Class I areas. As has been demonstrated in Section 7.0 of this application, the proposed project will neither cause nor contribute to violations of the Class I PSD increments (nor the AAQS) at the Okefenokee Wilderness Area, located 90 km to 145 km from the proposed source and Chassahowitzka Wilderness Area, located 110 to 129 km from the proposed source. Therefore, the additional impacts analysis section is limited to brief discussions of the issues at these distant locations.

8.2 IMPACTS DUE TO PROJECT-RELATED GROWTH

The growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the project. Only impacts related to permanent growth are considered; emissions from temporary sources and mobile sources are not addressed in the growth analysis.

There will be an average construction work force of 35 people with a peak work force of 120 required during the nine month construction period. It is anticipated that the majority of the construction workers will commute from their current residences. There will be no additional permanent jobs created by this project.

Development of industries supporting the new CT facility are expected to be negligible. Raw materials consumed by the facility (fuels, supplies, etc.) will be delivered to the site in usable form from outside of the region. Further processing, such as water treatment, will be accomplished entirely on site.

In summary, there will be no residential growth associated with the GRU project and there is little potential for new industrial development nearby as a result of the new facility. Although it is not possible to reliably quantify the secondary emissions and ambient air quality impacts resulting from the proposed project, these impacts are expected to be extremely small and well-distributed throughout the area.

8.3 VISIBILITY IMPACTS

Section 169A of the CAA Amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory PSD Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration due to various pollutants. Potential project impacts on visibility in the nearest Class I areas, the Okefenokee National Wilderness Area and the Chassahowitzka National Wilderness Area, were estimated using the VISCREEN Version 1.01 (88341) model (EPA, 1988b) recommended in the *Guideline to Air Quality Models* (Revised) (EPA, 1993a), impacts were calculated for PM and NO_2 in accordance with the model guidance and using the recommended defaults for the model.

The results of the VISCREEN analysis are presented in Figures 8-1 and 8-2. Based on these results, visible plumes from the project will not significantly impair visibility in the Okefenokee Wilderness Area or the Chassahowitzka Wilderness Area.

Visibility was also evaluated using the methodology presented in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase I Report: Interim Recommendation for Modeling Long Range Transport and Impacts on Regional Visibility* (EPA, 1993c). The IWAQM methods are intended to provide for an evaluation of the contributions of NO_x, SO_2, and PM emissions from a project to regional haze using a screening modelling methodology, and, if warranted, more complex modelling. The method accounts for chemical reactions of NO_x and SO_2 with NH_4 in the atmosphere to form particulates which are added to the primary PM_{10} emissions to produce regional haze. Since this IWAQM visibility evaluation was based on interim recommendations, Mr. John Viemont of the National Park Service Research Branch - Air Quality Division was contacted to obtain the most current changes to the methodology (Viemont, 1994). Mr. Viemont recommended that NO_x not be utilized in the evaluation because on the east coast there is typically insufficient ammonia gas (NH_3) available in the atmosphere to react with the nitrate (NO_3^-) and that any NH_3 that is available will preferentially react with the sulfate ($SO_4^=$) to form ammonium sulfate ($(NH_4)_2SO_4$). Another

Visual Effects Screening Analysis for
Source: DEERHAVEN STATION NEW CT
Class I Area: OKEFENOKEE NWA

*** Level-1 Screening ***

Input Emissions for

Particulates	1.90	G	/S
NOx (as NO2)	29.80	G	/S
Primary NO2	.00	G	/S
Soot	.00	G	/S
Primary SO4	.00	G	/S

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	25.00 km
Source-Observer Distance:	90.00 km
Min. Source-Class I Distance:	90.00 km
Max. Source-Class I Distance:	145.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	90.0	84.	2.00	.069	.05	-.000
SKY	140.	84.	90.0	84.	2.00	.021	.05	-.001
TERRAIN	10.	84.	90.0	84.	2.00	.003	.05	.000
TERRAIN	140.	84.	90.0	84.	2.00	.001	.05	.000

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	75.	87.1	94.	2.00	.072	.05	-.000
SKY	140.	75.	87.1	94.	2.00	.022	.05	-.001
TERRAIN	10.	60.	82.3	109.	2.00	.005	.05	.000
TERRAIN	140.	60.	82.3	109.	2.00	.001	.05	.000

Source: ENSERCH Environmental, 1994

GRU

VISCREEN Modelling Output
Okefenokee NWA

FIGURE
8-1

Visual Effects Screening Analysis for
Source: DEERHAVEN STATION NEW CT
Class I Area: CHASSAHOWITZKA NWA

*** Level-1 Screening ***

Input Emissions for

Particulates	1.90	G	/S
NOx (as NO2)	29.80	G	/S
Primary NO2	.00	G	/S
Soot	.00	G	/S
Primary SO4	.00	G	/S

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	25.00 km
Source-Observer Distance:	110.00 km
Min. Source-Class I Distance:	110.00 km
Max. Source-Class I Distance:	129.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	84.	110.0	84.	2.00	.023	.05	-.000
SKY	140.	84.	110.0	84.	2.00	.007	.05	-.000
TERRAIN	10.	84.	110.0	84.	2.00	.001	.05	.000
TERRAIN	140.	84.	110.0	84.	2.00	.000	.05	.000

Maximum Visual Impacts OUTSIDE Class I Area
Screening Criteria ARE NOT Exceeded

					Delta E		Contrast	
Backgrnd	Theta	Azi	Distance	Alpha	Crit	Plume	Crit	Plume
SKY	10.	75.	106.5	94.	2.00	.024	.05	-.000
SKY	140.	75.	106.5	94.	2.00	.007	.05	-.000
TERRAIN	10.	60.	100.6	109.	2.00	.001	.05	.000
TERRAIN	140.	60.	100.6	109.	2.00	.000	.05	.000

Source: ENSERCH Environmental, 1994

GRU

VISCREEN Modelling Output
Chassahowitzka NWA

FIGURE 8-2

recommended change to the IWAQM methodology was to utilize 3-hour averages rather than the 1-hour values for SO_2 and PM_{10} suggested in the IWAQM document.

The visibility impact evaluation using this methodology is based on the predicted change in the "deciview" value at the Class I area. The "deciview" is a new visibility index which is a relationship of a constant fractional change in extinction coefficient to perceived visual change (Pitchford and Malm, 1993). A pristine area will have a deciview (dv) value near zero and a one dv change is considered to be a small but perceptible change under many circumstances (CIRA, 1993).

The background of the Okefenokee Wilderness Area is approximately 22.2 dv and the background of the Chassahowitzka Wilderness area is about 21.9 dv (CIRA, 1993). The regional haze evaluation using the IWAQM Level I method utilizing the ISCST2 modelling results indicates that the deciview values may change to 24.1 and 24.0 at the Okefenokee and Chassahowitzka Wilderness Areas, respectively. The calculations used to derive the impacts of the sources are presented in Appendix E.

The results of this alternate method indicated that there would be a 1.9 dv increase at the Okefenokee Wilderness Area and a 2.1 dv change at the Chassahowitzka Wilderness Area. According to the Interagency Monitoring of Protected Visual Environment (IMPROVE) document *Spatial and Temporal Patterns and the Chemical Composition of Haze in the United States: An Analysis of Data from the Improve Network, 1988 - 1991* (CIRA, 1993) these changes would be small but perceptible. However, since the VISCREEN results indicated no visibility impact and since the IWAQM methods are currently only interim recommendations that have not been fully evaluated as to their applicability to the southeastern U.S., it is concluded that the project will not have a significant impact on visibility at either of the Class I areas.

8.4 IMPACT ON SOILS, VEGETATION AND AIR QUALITY RELATED VALUES

Potential air quality impacts of the proposed project were predicted at the PSD Class I Area portions of the Chassahowitzka National Wilderness Area and the Okefenokee National Wilderness Area. In addition to an evaluation of the effects on soils and vegetation, an Air Quality Related Values (AQRV) analysis is typically conducted to assess the potential risk to AQRV's of the two wilderness areas. The National Park Service and the Fish and Wildlife Service were contacted for guidance on the selection and analysis of AQRV's. Based on the distance of the proposed project to either the Chassahowitzka or the Okefenokee National

Wilderness Areas and the proposed emissions of SO_2 and NO_x, these agencies indicated that an AQRV analysis would not be necessary (Porter, 1994).

In order to evaluate the effects of SO_2 and NO_x on vegetation and soils in the impact area, a screening approach was used which compared the maximum predicted ambient concentrations of air pollutants of concern in the Chassahowitzka and Okefenokee National Wilderness Areas with effect threshold limits as reported in the scientific literature. During this evaluation, it was recognized that effect threshold values are not available for all species found in either the Chassahowitzka or the Okefenokee National Wilderness Area. However, studies have been performed on a few of the common species and on other similar species which can be used as models. The contribution from the proposed project was predicted using the ISCST2 model and five years of meteorological data as described in Sections 6.0 and 7.0.

8.4.1 Vegetation

The effects of air contaminants on vegetation occur primarily from sulfur dioxide, nitrogen dioxide, and particulates and are dependent both on the concentration of the contaminant and duration of the exposure. The term "injury", as opposed to "damage", is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. The maximum predicted impacts due to the proposed project for the 3-hour, 24-hour, and annual averaging periods are presented in Table 7-5. Each of these incremental levels due to the proposed project are extremely low especially in comparison to reported injury threshold levels. Existing background levels in the Chassahowitzka and the Okefenokee would have to be similar to those found in urban areas in order for the incremental increase from the proposed project to have an adverse effect on vegetation.

8.4.1.1 Sulfur Dioxide/Sulfuric Acid Mist

SO_2 is the air contaminant with the highest predicted emission level for the proposed project. The predicted maximum ground level 3-hour, 24-hour, and annual mean SO_2 concentrations due to the proposed project are 1.5, 0.32, and 0.005 $\mu g/m^3$ in the Chassahowitzka and 1.34, 0.34, and 0.005 $\mu g/m^3$ in the Okefenokee. In comparison, the 1-hour, 3-hour, and annual injury threshold concentrations as reported in the literature are 1,300, 400, and 118 $\mu g/m^3$. Existing annual average background concentrations would have to be in excess of 100 $\mu g/m^3$ to exceed the annual injury threshold concentrations when combined with the contribution of the proposed project. According to previous studies and from ambient monitoring data from regional air quality monitoring locations, annual background concentrations of SO_2 are in the range of 3-9 μg/m^3. Accordingly, no effects on vegetation are anticipated from the SO_2 levels from the proposed project.

The limited information available in the scientific literature suggests that sulfuric acid mist concentrations in excess of 100 μg/m^3 may have adverse effects on vegetation. The estimated concentration from the proposed project is 0.0357 μg/m^3 which is well below the value reported in the literature. Accordingly, there is no effect associated with the proposed project.

8.4.1.2 Nitrogen Dioxide

The maximum annual NO_2 concentration predicted to occur as a result of the proposed project in the Chassahowitzka and Okefenokee is 0.0047 μg/m^3. Assuming a background concentration of 10-13 μg/m^3 based on regional air quality monitoring data and an annual average injury threshold value of 470 μg/m^3, the predicted increase due to operation of the proposed project would not result in levels of NO_2 that would be injurious to vegetation.

8.4.1.3 Particulates

The maximum predicted ground-level 24-hour and annual concentrations of particulates (in the form of PM_{10}) due to the proposed project are 0.018 and 0.0003 μg/m^3 for the Chassahowitzka and 0.019 and 0.0003 μg/m^3 for the Okefenokee. Based on regional monitoring data, an annual background range of 18-29 μg/m^3 is estimated for particulates. No effects on vegetation are anticipated when the predicted concentrations from the proposed project are added to the estimated background concentrations, since these concentrations are below injury threshold values reported in the literature.

8.5 SOILS

Air contaminants can affect soils through fumigation by gaseous forms, accumulation of compounds transformed from the gaseous state, or by the direct deposition of particulate matter. Concentrations of SO_2 and NO_2 several orders of magnitude higher than the predicted values are required before any adverse effects from fumigation are observed. It is more likely that effects on soils could occur from the deposition of trace elements (mostly trace metals) in particulate matter. However, the predicted concentrations of particulate matter from the proposed project are so infinitesimally small that potential effects on soils are not anticipated.

9.0 CONCLUSION

The proposed project will apply BACT to control its emissions, will meet other state emission requirements, will comply with AAQS and PSD increment requirements, will not cause exceedances of FDEP's draft No Threat Levels, and will not cause any other significant air quality problems. Therefore, reasonable assurances have been provided to support FDEP's issuance of a PSD permit for the project.

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APPENDIX A

GE DATA SHEETS

GE Power Generation Engineering

Project Engineering
General Electric Company, Bldg. 53, Suite 200
One River Road, Schenectady, NY 12345 USA
Phone: (518) 385-9219 Dial Comm: 8*235-9219
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Date: October 6, 1993

Copies:
R Schubert 2-433
M Cardano Tampa Office
J. Hudson GVL-156
R Phelan 37-2 Annex
File/LB

Subject: **Gainesville Regional Utilities (GRU) DM#GR0292 Performance/Emissions Request**

To: Tom Putman
EBASCO Services Inc.
Atlanta Office
145 Technology Park
Atlanta, GA 30092

Enclosed are the performance/emissions tables you requested last month. Per M Cardano's telecon with Doug Beck of GRU only base load emissions at 95 F will be guaranteed, except for NOx which is guaranteed at all load points in the attached tables. All other emissions values are estimated and may be used for information. While we don't expect the reported values to vary significantly, some values may change as the DLN combustion system, including the control system and operating scheme get fine tuned.

Three changes have occurred to the fuel oil runs since we originally submitted performance data in our proposal. First the water injection rates on oil fuel have been adjusted downward, based on latest test data on the DLN combustor. You will note some related changes in the performance which are directly related to water injection rate. Second, since GRU has requested estimated NOx with extremely high fuel bound nitrogen (0.14% by wt.) we have increased our estimated yield (ratio of nitrogen in fuel to NOx produced organically in exhaust). Therefore the first number under NOx for the distillate runs reflects expected NOx with 0.14% (by weight) fuel bound nitrogen (100 ppmvd @ 15% O2, of which 42 ppmvd is thermal NOx and the remaining 58 ppmvd is organic NOx) and the second number is expected NOx with 0.03% fuel nitrogen, as you requested. Lastly the two numbers in the sulfur emissions row on the distillate runs reflect the original 0.46% (by weight) fuel sulfur and the second number reflects the lower 0.05% (by weight) fuel sulfur level.

Michael A. Davi
Michael A. Davi, Project Leader
GT Applications Engineering

md/enclosure

Case: tural Gas , Dry Low NO_x Combustor
Inlet Guide Vane Position 100% Open @ Base Only

Load Level - %	100	80	60	100	80	60	
Ambient Temperature - °F	20	20	20	75	75	75	
Relative Humidity - %	100	100	100	90	90	90	
Gross Output - kW (at Gen. Terminals)	94340	75230	56420	78760	63050	47250	
Auxiliary Power and Losses - kW (GT)	450	450	450	450	450	450	
Net Output - kW	93890	74780	55970	78310	62600	46800	
Firing Temperature - °F (Nom)	2020	2007	2000	2020	2009	2002	
Net Heat Rate (HHV) - Btu/kWh	11440	12100	13850	11900	12790	14780	
Heat Cons. (HHV) $x10^6$ - Btu/hr	1074.5	896.0	760	931.1	792.9	672.1	
Exhaust Mass Flow $x10^3$ - lb/hr	2550	2087	1753	2247	1869	1580	
Exhaust Temp - °F	964	988	1037	1001	1037	1086	
Water Injection Flow - lb/hr	0	0	0	0	0	0	
Fuel Flow - lb/hr	44990	37520	31810	38990	33210	28390	
Exhaust Analysis							
NO_x - ppmvd @ 15% O_2	15	15	15	15	15	15	
NO_x as NO_2 - lb/hr	58	49	41	51	43	37	
CO - ppmvd	15	15	15	15	15	15	
CO - lb/hr	35	29	24	31	26	21	
Total VOC - ppmvw	2	2	2	2	2	2	
Total VOC - lb/hr	3	3	3	2.7	2.7	2.7	
Non Methane HC - ppm	2	2	2	2	2	2	
Non Methane HC - lb/hr	3	3	3	2.7	2.7	2.7	
Particulate - lb/hr	7	7	7	7	7	7	
Particulate - PM_{10} lb/hr	7	7	7	7	7	7	
Particulate - TSP lb/hr	7	7	7	7	7	7	
SO_2 - ppmvd	Trace						
SO_2 - lb/hr	Trace						
SO_3 - ppmvw	Trace						
SO_3 - lb/hr	Trace						
Opacity - %	10	10	10	10	10	10	
Argon Ar - % Vol	0.90	0.91	0.90	0.90	0.88	0.88	
Nitrogen N_2 - % Vol	75.36	75.32	75.32	73.68	73.62	73.62	
Oxygen O_2 - % Vol	13.93	13.86	13.85	13.64	13.53	13.50	
Carbon Dioxide CO_2 - % Vol	3.22	3.20	3.21	3.09	3.14	3.15	
Water H_2O - % Vol	6.59	6.71	6.72	8.70	8.83	8.85	

Case: Natural Gas, Dry Low NO_x Combustor
Inlet Guide Vane Position 100% Open @ Base Only

Load Level - %	100	80	60	100	90	80	60
Ambient Temperature - °F	95	95	95	ISO	ISO	ISO	ISO
Relative Humidity - %	50	50	50	ISO	ISO	ISO	ISO
Gross Output - kW (at Gen. Terminals)	72030	58980	44130	82810	75050	66620	50070
Auxiliary Power and Losses - kW	450	450	450	450	450	450	450
Net Output - kW	71580	58530	43680	82360	74600	66170	49620
Firing Temperature - °F (Nom)	2020	2010	2008	2020	2013	2007	2002
Net Heat Rate (HHV) - Btu/kWh	12130	13090	15160	11790	11940	12550	14420
Heat Cons. (HHV) $x10^6$ - Btu/hr	868.3	758.8	649	971.1 ~~875~~	886	821.5	701.9
Exhaust Mass Flow $x10^3$ - lb/hr	2137	1795	1530	2343	2100	1937	1636
Exhaust Temp - °F	1011	1058	1100	989	1005	1022	1072
Water Injection Flow - lb/hr	0	0	0	0	0	0	0
Fuel Flow - lb/hr	~~37500~~ 36400 DJA	31800	27200	40700	37140	34420	29410
Exhaust Analysis							
NO_x - ppmvd @ 15% O_2	15	15	15	15	15	15	15
NO_x as NO_2 - lb/hr	47	41	35	53	48	44	38
CO - ppmvd	15	15	25	15	15	15	15
CO - lb/hr	29	24	35	32	29	27	23
Total VOC - ppmvw	2	2	2	2	2	2	2
Total VOC - lb/hr	2.6	2.6	2.6	2.8	2.8	2.8	2.8
Non Methane HC - ppm	2	2	2	2	2	2	2
Non Methane HC - lb/hr	2.6	2.6	2.6	2.8	2.8	2.8	2.8
Particulate - lb/hr	7	7	7	7	7	7	7
Particulate - PM_{10} lb/hr	7	7	7	7	7	7	7
Particulate - TSP lb/hr	7	7	7	7	7	7	7
SO_2 - ppmvd	Trace						
SO_2 - lb/hr	Trace						
SO_3 - ppmvw	Trace						
SO_3 - lb/hr	Trace						
Opacity - %	10	10	10	10	10	10	10
Argon Ar - % Vol	0.88	0.89	0.88	0.90	0.89	0.90	0.90
Nitrogen N_2 - % Vol	73.61	73.53	73.54	74.91	74.88	74.86	74.86
Oxygen O_2 - % Vol	13.72	13.53	13.55	13.93	13.84	13.83	13.80
Carbon Dioxide CO_2 - % Vol	3.09	3.13	3.12	3.11	3.16	3.16	3.17
Water H_2O - % Vol	8.71	8.93	8.91	7.15	7.13	7.25	7.27

Ca. : Natural Gas , Dry Low NO_x Combustor, Power Augmentation
Inlet Guide Vane Position 100% Open @Base Only

Load Level - %	100	100	90	80	60		
Ambient Temperature - °F	95	ISO	ISO	ISO	ISO		
Relative Humidity - %	50	ISO	ISO	ISO	ISO		
Gross Output - kW (at Gen. Terminals)	78710	89580					
Auxiliary Power and Losses - kW	450	450					
Net Output - kW	78260	89130					
Firing Temperature - °F (Nom)	2020	2020					
Net Heat Rate (HHV) - Btu/kWh	12600	12300					
Heat Cons. (HHV) $x10^6$ - Btu/hr	986.1	1096.6					
Exhaust Mass Flow $x10^3$ - lb/hr	2189	2396					
Exhaust Temp - °F	1014	990					
Water Injection Flow - lb/hr	51370	56920					
Fuel Flow - lb/hr	42590	45920					
Exhaust Analysis							
NO_x - ppmvd @ 15% O_2	30	30					
NO_x as NO_2 - lb/hr	107	120					
CO - ppmvd	20	20					
CO - lb/hr	38	42					
Total VOC - ppmvw	3	3					
Total VOC - lb/hr	4	4.5					
Non Methane HC - ppm	3	3					
Non Methane HC - lb/hr	4	4.5					
Particulate - lb/hr	7	7					
Particulate - PM_{10} lb/hr	7	7					
Particulate - TSP lb/hr	7	7					
SO_2 - ppmvd	Trace	→					
SO_2 - lb/hr	Trace	→					
SO_3 - ppmvw	Trace	→					
SO_3 - lb/hr	Trace	→					
Opacity - %	10	10					
Argon Ar - % Vol	0.85	0.86					
Nitrogen N_2 - % Vol	70.64	71.85					
Oxygen O_2 - % Vol	12.36	12.57					
Carbon Dioxide CO_2 - % Vol	3.37	3.43					
Water H_2O - % Vol	12.78	11.29					

No power aug. when below base.

Ca[illegible] Fuel Oil, Dry Low NO_x Combustor
Inlet Guide Vane Position 100% Open @ Base Only

Load Level - %	100	80	60	100	80	60	
Ambient Temp - °F	20	20	20	75	75	75	
Relative Humidity - %	100	100	100	90	90	90	
Gross Output - kW	96940	77660	58110	80280	64150	48190	
Auxiliary Power and losses- kW	475	475	475	475	475	475	
Net Output - kW	96465	77185	57635	79805	63675	47715	
Firing Temperature - °F (Nom)	2020	2000	1990	2020	2000	1990	
Net Heat Rate (HHV) - Btu/kWh	11400	12120	13850	11760	12650	14540	
Heat Cons. (HHV) $x10^6$ - Btu/hr	1100	926	782.9	938.6	798	680	
Exhaust Flow $x10^3$ - lb/hr	2610	2055	1741	2285	1864	1596	
Exhaust Temp - °F	955	1001	1068	994	1050	1086	
Water Injection Flow - lb/hr	45070	37150	30060	31640	25310	20050	
Fuel Flow - lb/hr	55940	47100	39820	47740	40600	34600	
<u>Exhaust Analysis</u> FBN							
* NO_x - ppmvd @ 15% O_2 (0.4%)/(0.03%)	100/54	100/54	100/54	100/54	100/54	100/54	
NO_x as NO_2 - lb/hr	437/237	365/197	307/166	372/201	315/170	266/144	
CO - ppmvd	30	30	40	30	30	40	
CO - lb/hr	71	56	63	62	50	58	
VOC - ppmvw	5	5	5	5	5	5	
VOC - lb/hr	7	6	5	6	5	5	
Sulfuric Acid Mist - lb/hr (0.46%/0.05%)	51/6	44/5	37/4	44/5	37/4	32/4	
Particulate - PM_{10} lb/hr	15	15	15	15	15	15	
Particulate - TSP lb/hr	15	15	15	15	15	15	
SO_2 - ppmvd (0.46% / 0.05%)	85/10	90/10	90/10	83/9	85/9	85/9	
SO_2 - lb/hr (" / ")	490/53	411/45	348/38	416/45	354/39	301/33	
SO_3 - ppmvw (" / ")	5/1	5/1	5/1	5/1	5/1	5/1	
SO_3 - lb/hr (" / ")	30/3	28/3	23/3	28/3	23/3	21/3	
Opacity - %	20	20	20	20	20	20	
Argon Ar - % Vol	0.88	0.90	0.89	0.87	0.88	0.88	
Nitrogen N_2 - % Vol	73.85	73.64	73.75	72.63	72.68	72.72	
Oxygen O_2 - % Vol	13.16	12.70	12.80	13.04	12.80	12.92	
Carbon Dioxide CO_2 - % Vol	4.35	4.60	4.56	4.21	4.35	4.30	
Water H_2O - % Vol	7.76	8.17	8.00	9.25	9.39	9.18	

* 42 ppmvd @ 15% O_2 if FBN ≤ 0.015% by wt.

Cas... el Oil, Dry Low NO_x Combustor
Inlet Guide Vane Position 100% Open @ Base Only

Load Level - %	100	80	60	100	90	80	60
Ambient Temp - °F	95	95	~~90~~ 95	ISO	ISO	ISO	ISO
Relative Humidity - %	50	50	50	ISO	ISO	ISO	ISO
Gross Output - kW	74370	59410	44620	85580	76990	68520	51370
Auxiliary Power and losses - kW	475	475	475	475	475	475	475
Net Output - kW	73895	58935	44145	85105	76515	68045	50895
Firing Temperature - °F (Nom)	2020	2010	1990	2020	2008	2000	1995
Net Heat Rate (HHV) - Btu/kWh	11960	12940	14920	11640	11950	12470	14300
Heat Cons. (HHV) $x10^6$ - Btu/hr	883.7	755.7	646.1	990.6	905	840	714
Exhaust Flow $x10^3$ - lb/hr	2178	1798	1548	2390	2093	1927	1644
Exhaust Temp - °F	1007	1058	1092	981	1020	1042	1080
Water Injection Flow - lb/hr	29770	23650	18680	39420	35140	31930	25600
Fuel Flow - lb/hr	44940	38430	32860	50380	46030	42746	36310
Exhaust Analysis							
* NO_x - ppmvd @ 15% O_2 (0.14%/0.03%)	100/54	100/54	100/54	100/54	100/54	100/54	100/54
NO_x as NO_2 - lb/hr	351/189	298/161	253/137	394/213	357/193	332/179	279/151
CO - ppmvd	30	30	40	30	30	30	40
CO - lb/hr	59	48	56	65	57	53	60
VOC - ppmvw	5	5	10	5	5	5	10
VOC - lb/hr	6	6	9	6	6	6	9
Sulfuric Acid Mist - lb/hr (0.46%/0.05)	41/5	35/4	30/3	46/5	41/5	39/4	35/4
Particulate - PM_{10} lb/hr	15	15	15	15	15	15	15
Particulate - TSP lb/hr	15	15	15	15	15	15	15
SO_2 - ppmvd (0.46%/0.05%)	81/9	85/9	83/9	83/9	87/10	87/10	87/10
SO_2 - lb/hr (" / ")	393/43	336/37	298/31	439/48	403/44	373/41	318/35
SO_3 - ppmvw (" / ")	5/1	5/1	5/1	5/1	5/1	5/1	5/1
SO_3 - lb/hr (" / ")	25/3	25/3	18/2	30/3	25/3	25/3	21/2.5
Opacity - %	20	20	20	20	20	20	20
Argon Ar - % Vol	0.87	0.87	0.88	0.89	0.88	0.89	0.88
Nitrogen N_2 - % Vol	72.57	72.56	72.71	73.50	73.39	73.40	73.55
Oxygen O_2 - % Vol	13.10	12.93	13.06	13.18	12.91	12.88	12.99
Carbon Dioxide CO_2 - % Vol	4.16	4.27	4.21	4.27	4.43	4.45	4.40
Water H_2O - % Vol	9.30	9.37	9.14	8.17	8.39	8.39	8.18

* 42 ppmvd @ 15% O_2 if FBN ≤ 0.015% by wt.

APPENDIX B

NORTON CHEMICAL SCR COST ESTIMATE

NORTON CHEMICAL PROCESS PRODUCTS CORPORATION

P.O. Box 350
Akron, Ohio 44309-0350
(216) 673-5860

November 3, 1993

Ebasco Environmental
759 South Federal Highway
Stuart, Fla   34994-2936

Fax No. (407) 225-9463   Pages: 4

Attn: Darrel Graziani

Re: GE MS7001EG gas turbine
Norton Project Number NC93193

Dear Mr. Graziani:

Norton Company is pleased to submit our preliminary proposal to supply an NC-300 SCR Catalyst System to control NOx emissions from a combustion turbine. We have based our estimate on the 0.14% N fuel oil case, since this represents the worst case condition. The design will cover both the natural gas and fuel oil firing conditions.

A. NC-300 Catalyst System $ 3,939,000.00

The above price includes:
- NC-300 SCR Catalyst
- CO Oxidation Catalyst
- Catalyst Modules
- Hot Wall Reactor Housing
- Ammonia Injection Grid
- Ammonia Dilution and Flow Control Skid
- Ammonia Storage Tank
- Engineering Specifications
- Continuous Emissions Monitoring System

The system does not include:
- Interconnecting Piping and Wiring
- Field Installation

Please refer to the attached Preliminary Mechanical Design and Performance data sheets labeled NC93193-1 for more details. Please note that our current maximum operating temperature for the NC-300 Catalyst is 1050 Deg F. In the future it may be feasible to extend this to cover the maximum temperatures indicated in your data sheets. Otherwise, we would need to inject ambient air into the exhaust in order to control the maximum temperature limit.

The standard performance warranty for this type of NC-300 SCR System covers the NOx reduction and ammonia slip performance of the system for a period of three years or 24000 operating hours, whichever comes first. The expected catalyst life is three to five years after which time catalyst replacement may become necessary. The expected NC-300 SCR catalyst replacement cost for a reactor of this size is $ 934,731.00 per catalyst layer.

The typical CO oxidation catalyst warranty is one year or 8000 hours, whichever comes first. The estimated CO catalyst replacement cost is $ 750,000.00 per layer.

Thank you for allowing the Norton Company this opportunity to present our products. If you have any questions or additional requirements, please do not hesitate to contact us.

Sincerely,

NORTON Chemical Process Products Corporation

Stephen M. Turner
Manager, Sales and Marketing,
Environmental Products

Customer: Ebasco Environmental
Project Ref: GE MS7001EG gas turbine
Case: 0.14% N fuel oil

SELECTIVE CATALYTIC REDUCTION UNIT

REACTOR DESIGN AND PERFORMANCE CONDITIONS

Norton NC93193-1

1.0 Preliminary Mechanical Design

1.1 Manufacturer — Norton Company

1.2 Arrangement — Horizontal flow

1.3 Catalyst Module nominal dimensions (ft)
height x width x depth CO: 6.0 x 6.0 x 0.5
NOx: 6.50 x 6.50 x 0.82

The CO catalyst bed will be arranged in (1) layer
The NOx catalyst bed will be arranged in (2) layers

1.4 Reactor Inside Dimensions (ft)
height x width x depth CO: 30.0 x 30.0 x 1.0
NOx: 45.5 x 45.5 x 4.0

Total reactor length, including CO, ammonia injection grid and NOx catalyst: 15.0 ft

Reactor dimensions are approximate; depth does not include space for additional catalyst layers

1.5 No. of Catalyst Modules CO: 25
NOx: 98

1.6 Materials of Construction (Hot Wall Reactor)

Catalyst Modules	AISI 304 SS
Module Support Framework	AISI 304 SS
Reactor Housing Wall/Supports	AISI 409 SS
Catalyst Type	NC-300 Zeolite-based 100 cell/sq.in. honeycomb
Insulation	Mineral Wool with 0.016 inch aluminum cover

1.7 Maximum Allowable Catalyst Temp (F) — 1050

1.8 Total Pressure Drop (in H2O) — 6.0

1.9 Notes:

Customer: Ebasco Environmental
Case: 0.14% N fuel oil

SELECTIVE CATALYTIC REDUCTION UNIT

Norton NC93193-1

2.0 Performance

2.1	Gas Flow Rate (wet basis)		
	Exhaust Gas (lb/hr)		2610000
	Exhaust Gas (ACFM)		1601889
2.2	Flue Gas Composition (mole %)		
	Nitrogen (N2)	73.85	
	Carbon Dioxide (CO2)	4.35	
	Water (H2O)	7.76	
	Oxygen (O2)	13.16	
	Argon (AR)	0.88	
	TOTAL PERCENT	100.00	
	SOx (ppmv)		85.0
	Molecular Weight		28.6
	CO (ppmv)		30.0
	Inlet NOx based on exhaust gas flow; as NO2		
	lb/hr		435.1
	ppmvd @ 15.0% O2		100.0
2.3	Flue Gas Temperature (F)		
	Design		981
	Range	955	to 1080
2.4	Flue Gas Pressure Drop (in. H2O)		
	Across CO catalyst		1.5
	Across AIG		0.1
	Across NOx Catalyst		3.0
2.5	Ammonia Consumption (lb/hr 25.0% aq.)		550.9
2.6	Dilution Media Flow Rate		
	Air (SCFM)		881
2.7	Ammonia Slip (ppmv)		< 10
2.8	NOx Conversion Efficiency (%)		76.0
2.9	CO Conversion Efficiency (%)		70.0
2.10	Outlet NOx based on exhaust gas flow; as NO2		
	lb/hr		104.4
	ppmvd @ 15.0% O2		24.0

APPENDIX C

REVISED NORTON CHEMICAL
SCR COST ESTIMATE INCLUDING AIR INJECTION

NORTON CHEMICAL PROCESS PRODUCTS CORPORATION

NORTON

P.O. Box 350
Akron, Ohio 44309-0350
(216) 673-5860

FACSIMILE TRANSMISSION COVER SHEET
Norton Fax (216) 677-3609

TO: Ebasco Environmental

DATE: November 23, 1993

ATTN: Darrel Graziani

No. PAGES: 1

FAX: 407-225-9463

REF: GE MS7001EG gas turbine
Norton Project Number NC93193

Dear Mr. Graziani:

In reply to your revised conditions for the subject inquiry, we can revise our previous budgetary quotation as follows:

1. Budget price of Nov. 3, 1993:	$ 3,939,000.00
2. Delete CO oxidation catalyst:	- $ 743,000.00
3. Add exhaust cooling air system:	+ $ 83,000.00
TOTAL REVISED PRICE	$ 3,279,000.00

We estimate the additional cooling air required for the high temperature case (1080 Deg F) will be about 32,000 SCFM. Since the highest temperatures occur at the 60% load condition, the total exhaust flow through the catalyst is still lower than the total flow at 100% load. Thus, the 100% load condition is still the design basis for sizing the catalyst reactor. Our previous reactor sizing would still apply for the revised outlet NOx limits (11.7 ppmv for oil, 3.5 ppmv for natural gas).

I hope this additional information will be helpful. Please let us know how we can be of further assistance as this project proceeds.

Sincerely,

NORTON Chemical Process Products Corporation

Stephen M. Turner
Manager, Sales & Marketing,
Environmental Products

APPENDIX D

FDEP AIR TOXICS MEMORANDUM

Memorandum

Florida Department of
Environmental Protection

TO:	Ed Middleswart	NW District
	Chris Kirts	NE District
	Chuck Collins	Central Florida District
	Bill Thomas	SW District
	David Knowles	South Florida District
	Isidore Goldman	SE District
	Al Linero	Broward County
	H. Patrick Wong	Dade County
	Steve Pace	Duval County
	Iwan Choronenko	Hillsborough County
	Jim Stormer	Palm Beach County
	Peter Hessling	Pinellas County
	J. Kent Kimes	Sarasota County
	Dennis Nester	Orange County
	Dotty Diltz	Bureau of Air Monitoring and Mobile Sources
	Clair Fancy	Bureau of Air Regulation

FROM: Howard L. Rhodes, Director
Division of Air Resources Management

DATE: November 29, 1993

SUBJECT: Air Toxics Program Development and Use of Air Toxics Permitting Strategy

By January 1994, the EPA expects to promulgate eight air toxics rules under Section 112 of the Clean Air Act. Maximum achievable control technology (MACT) standards for as many as 28 source categories are expected to be issued or proposed by the end of 1994. (The first of these standards, for commercial and industrial dry cleaners, was published September 22.) Furthermore, the state must adopt a hazardous air pollutant (HAP) new source review rule and a MACT "hammer" rule by the Fall of 1994 to be eligible to receive delegation of the Title V permitting program.

This memo is to update you on how the Division will be responding to these new requirements organizationally and to identify some of the key issues that will need to be addressed. It is also intended to provide new guidance on use of the "air toxics permitting strategy" modeling methodology.

Air Toxics Subsection

The Air Toxics Subsection in the Office of Policy Analysis and Program Management (SC 278-0114) will continue to be the focal point for all air toxics program development activities. John Glunn will be the lead contact for the overall program, including all grant-related and rulemaking activities. Tom Savage and Beth Hardin will be assigned responsibility for tracking specific EPA activities and disseminating information to other air program staff as needed. For example, Beth is currently analyzing the dry cleaner NESHAP and the proposed "general provisions" of 40 CFR 63; Tom is following the HON and the "early reductions" program.

The Air Toxics Subsection will function primarily as a planning and development group. As elements of the air toxics program (permitting, compliance, source sampling, emissions reporting, and ambient monitoring) become integrated into the operational units of the air program throughout the state, the Air Toxics Subsection will be available to provide technical support.

Florida Air Toxics Working Group (FLATWG)

The Florida air toxics working group was established prior to passage of the Clean Air Act Amendments of 1990 to develop recommendations for a state air toxics control program. Since then, the role of the group has changed. Now, the primary function of FLATWG is to facilitate implementation of the federal air toxics program in Florida. Each district and local air program, as well as the two DARM bureaus, should designate a FLATWG representrative. The Air Toxics Subsection will work through the FLATWG representatives to keep air program staff in all offices informed of air toxics developments and to share ideas on how to respond to the various EPA requirements. The group will continue to hold periodic teleconferences and meet in a half-day session at the Annual Air Meeting.

Air Toxics Program Development Issues

The major issues to be addressed in the development of Florida's air toxics program are as follow:

1. Adoption by reference of federal standards: How should this be handled on an ongoing basis? What, if any, standards should not be adopted? How should implementation of the standards through the permitting process be coordinated? How should compliance with area-source standards be assured?

2. Rule development at state level: How should the Department respond to the need for HAP new source review and MACT hammer rules to obtain Title V delegation, especially in the absence of final EPA rules? What role, if any, should a procedure similar to the current air toxics permitting strategy play in this rulemaking?

3. Accidental release program: What role, if any, should the district and local programs assume in implementation of the Section 112(r) program in Florida? Should routine compliance inspections be used to verify that sources are adhering to their risk management plans?

4. Air toxics assessment: How and to what extent should air toxics assessment activities such as emissions inventories, emission speciation studies, high-risk point source evaluations, ambient monitoring programs, receptor modeling studies, ecosystem assessments, and risk assessments be carried out?

The Air Toxics Subsection, with input from FLATWG, will be considering these issues over the next several months and developing options for our consideration.

Air Toxics Permitting Strategy

Special mention must be made of the "air toxics permitting strategy" and its use in the emerging air toxics program. The strategy was developed several years ago as a tool to assist district and local program air permit engineers in evaluating permit applications that involved significant emissions of hazardous air pollutants. Indeed, the strategy has been effective in addressing air toxics in a flexible manner, and its use was upheld in a permit hearing. At one point, the Division intended to eventually adopt the strategy as part of a state air toxics rule. However, this plan was changed by passage of the Clean Air Act Amendments of 1990.

In the future, the control of HAP emissions in Florida will be dominated by the programs and standards developed under Title III of the Clean Air Act Amendments of 1990. Once the Title V operating permit program is approved by EPA, all Title III permitting requirements will become federally enforceable permit conditions within the Title V permits. On the other hand, any HAP emission limit or work practice standard based on a state program different than Title III (such as our toxics permitting strategy) will not be made a federally enforceable Title V permit condition unless EPA has approved the state program under Section 112(l) of the Act or the applicant accepts the permit condition for other reasons. There are no plans to seek approval of our permitting strategy since it would involve formally adopting the strategy as an alternative to the federal program.

This is not to imply that the strategy will no longer serve a useful purpose. Section 112(g) requires states to develop rules that will require new or modified sources proposing to increase hazardous air pollutant emissions above "de minimis" amounts to undergo case-by-case MACT determinations. How EPA will define "de minimis" is not certain, but it may involve a process that is similar to our strategy. Once a de minimis threshold is exceeded, the case-by-case MACT process may require that ambient concentrations, and resultant health impacts, be considered along with other factors in determining the appropriate MACT standard. Therefore, the strategy continues to reflect incipient agency rulemaking, though the final direction of this rulemaking is uncertain at this time.

In any case, if the air toxics permitting strategy is to function in the context of Title III and Title V, it must be revised. First, it must be viewed as an air toxics "evaluation tool" rather than a "permitting strategy." Second, it must be limited in its application to the 189 hazardous air pollutants currently regulated under Title III and state law. Third, the modeling protocol needs to use the better air dispersion models now available. Fourth, the source of each of the health benchmarks chosen to define a reference ambient concentration must be clear and defensible. Finally, the term "no threat level" must be changed to more accurately reflect the purpose of these values. Anticipate that changes to the strategy in line with these points will be discussed at the Annual Air Meeting.

In the meantime, you may use the strategy as a tool during those preconstruction reviews where an apparent public health threat exists. However, do not consider pollutants other than the 189 currently regulated HAPs. Also, do not use the strategy in the context of operation permit renewals. The "no threat levels" are not environmental standards; therefore, a predicted concentration in excess of any such level is not an automatic grounds for permit denial. Other factors, such as the reasonableness of the proposed control technology should be considered.

If you wish to discuss these issues further, please call John Glunn at 904/488-0114.

HLR/jg/p

cc: Larry George
John Glunn
Tom Savage
Beth Hardin
Tom Rogers

APPENDIX E

IWAQM VISIBILITY CALCULATIONS

GAINESVILLE REGIONAL UTILITES
DEERHAVEN STATION
NEW 74 MW CT

Class I Visibility calculations per IWQAM Document
Appendix B - Method for Calculating Regional Visibility Impairment

SO_2 Maximum 3-hour average at the Okeefenokee NWA 0.26700 ug/m^3

PM_{10} Maximum 3-hour average at the Okeefenokee NWA 0.07594 ug/m^3

$SO_4^=$ equals 1.5 times SO2 per page 5-5 of IWAQM Document

$$1.5 \cdot 0.26700 = 0.4005$$

NH_4SO_2 equals 1.375 times $SO_4^=$ per Appendix B of IWAQM Documnet

$$NH_4SO_2 = 1.375 \cdot 0.4005 = 0.55069$$

[$b_{ext.s}$] =0.003 * {part} * fRH This formula is from page B-1 of the IWAQM Document

Where: $b_{ext.s}$ = the extinction coefficient due to particle scattering (km^{-1})

0.003 = a nominal dry scattering efficiency
{part} = the particulate concentration in ug/m3
fRH = the RH correction factor (11.5 at the assumed *rh* of 95%)
(the fRH is from page B-3 of the IWAQM Document)

$$NH_4SO_2(b_{ext}) = 0.003 \cdot 0.55069 \cdot 11.5 = 0.01900$$

$$PM_{10}(b_{ext}) = 0.003 \cdot 0.07594 = 0.00023$$

$$\text{Total of } NH_4SO_2 \text{ and } PM_{10} = 0.01900 + .00023 = 0.01923$$

$$dv = 10\ln(b_{ext} / 0.01\ \text{km}^{-1})$$

Where: dv = Deciviews
b_{ext} = the extinction coefficient (km^{-1})

$$dv(\text{contribution from source}) = 10 \cdot \ln\left(\frac{0.01923}{0.01}\right) = 6.5$$

background extinction coefficient from IMPROVE Document page S-7 figure S.2(a)
92 Mm^{-1} = 0.092 km^{-1}

$$dv(\text{background}) = 10 \cdot \ln\left(\frac{0.092}{0.01}\right) = 22.2$$

$$dv(\text{background + source}) = 10 \cdot \ln\left[\frac{(0.0920 + 0.01923)}{0.01}\right] = 24.1$$

Difference of (background + source) minus Background (dv) = $24.1 - 22.2 = 1.9$

GAINESVILLE REGIONAL UTILITES
DEERHAVEN STATION
NEW 74 MW CT

Class I Visibility calculations per IWQAM Document
Appendix B - Method for Calculating Regional Visibility Impairment

SO_2 Maximum 3-hour average at the Chassakowitzka NWA 0..30307 ug/m^3

PM_{10} Maximum 3-hour average at the Chassakowizka NWA 0..08620 ug/m^3

$SO_4^=$ equals 1.5 times SO2 per page 5-5 of IWAQM Document

$1.5 \cdot 0.30307 = 0.45461$

NH_4SO_2 equals 1.375 times $SO_4^=$ per Appendix B of IWAQM Documnet

$NH_4SO_2 = 1.375 \cdot 0.45461 = 0.62509$

$[b_{ext.s}] = 0.003 * \{part\} * fRH$ This formula is from page B-1 of the IWAQM Document

Where: $b_{ext.s}$ = the extinction coefficient due to particle scattering (km^{-1})
0.003 = a nominal dry scattering efficiency
{part} = the particulate concentration in ug/m3
fRH = the RH correction factor (11.5 at the assumed rh of 95%)
(fRh is set to 1 for fine particulates p B-2 IWAQM Document)
(the fRH is from page B-3 of the IWAQM Document)

$NH_4SO_2(b_{ext}) = 0.003 \cdot 0.62509 \cdot 11.5 = 0.02157$

$PM_{10}(b_{ext}) = 0.003 \cdot 0.08620 \cdot 1 = 0.00026$

Total of NH_4SO_2 and PM_{10} = $0.02157 + .00026 = 0.02183$

$dv = 10\ln(b_{ext} / 0.01\ km^{-1})$

Where: dv = Deciviews
b_{ext} = the extinction coefficient (km^{-1})

dv(contribution from source)= $10 \cdot \ln\left(\frac{0.02183}{0.01}\right) = 7.8$

background extinction coefficient from IMPROVE Document page S-7 figure S.2(a)
89 Mm^{-1} = 0.089 km^{-1}

dv(background) = $10 \cdot \ln\left(\frac{0.089}{0.01}\right) = 21.9$

dv(background + source) = $10 \cdot \ln\left[\frac{(0.0890 + 0.02183)}{0.01}\right] = 24.1$

Difference of (background + source) minus Background (dv) = $24.1 - 21.9 = 2.2$

HOPPING BOYD GREEN & SAMS
ATTORNEYS AND COUNSELORS
123 SOUTH CALHOUN STREET
POST OFFICE BOX 6526
TALLAHASSEE, FLORIDA 32314
(904) 222-7500
FAX (904) 224-8551
FAX (904) 681-2964

March 22, 1994

Mr. Hamilton S. Oven
Siting Coordinator
Florida Department of Environmental
Protection
3900 Commonwealth Blvd., Suite 953
Tallahassee, FL 32399

Re: Gainesville Regional Utilities
Deerhaven Unit No. 2, PA 74-04
Proposed Agreement to Modify Conditions of Certification
Combustion Turbine Project

Dear Mr. Oven:

Pursuant to Section 403.516(1)(b), Florida Statutes, I am submitting, on behalf of the City of Gainesville, Gainesville Regional Utilities (GRU), a Proposed Agreement to Modify the Site Certification for Deerhaven Unit No. 2. The cited statute authorizes the Department of Environmental Protection (DEP) to modify the certification, including the conditions of certification, when no objection is raised by a party or person whose substantial interests will be affected by the proposed modification. GRU is also simultaneously submitting to the Department an application for a Prevention of Significant Deterioration permit for this project.

The Siting Board's original certification order authorizing construction and operation of Deerhaven Unit No. 2 was issued on May 16, 1978. By this Proposed Agreement, GRU requests approval of a modification of the certification to authorize GRU to construct and operate a new simple cycle combustion turbine on a one-acre parcel within the Deerhaven Plant site, as described in the attached documents.

This combustion turbine, its location and expected impacts are discussed in greater detail in the attached modification submittal and PSD permit application. No changes to the existing facilities at the Deerhaven site or other new facilities will be required as a result of this modification. The location of the new CT is adjacent to the existing gas turbines at the Deerhaven site on an upland area of the site. No wetlands will be impacted by the project. The CT will utilize existing facilities on the site such as fuel supply and storage facilities and existing transmission systems serving the Deerhaven site.

GRU is requesting a modification of the certification, including additional conditions of certification, that will authorize the construction and operation of this new combustion turbine. Those proposed conditions are attached to the Proposed Agreement for Modification of Certification. These additional conditions of certification will allow the construction of the combustion turbine to proceed following the Department's issuance of this modification request.

GRU requests that the Department issue an order pursuant to section 403.516(1)(b), F.S., modifying the terms and conditions of the certification upon no objection being raised by a party or substantially affected person. The modification order should contain the attached conditions and any additional necessary or revised conditions proposed by agency parties and accepted by GRU.

In accordance with DEP's regulations, we have forwarded copies of this Proposed Agreement by hand delviery or certified U.S. mail to those parties in the original certification proceedings, as indicated in the Certificate of Service to the attached Agreement for Modification of Certification. Copies of this Request are also being provided to the persons and agencies identified below.

An application fee in the amount of $10,000, (Check No. 17092), payable to DEP, is being submitted with this proposed agreement. If you or any of the parties have questions or comments on this request, please contact either Yolanta Jonynas of GRU in Gainesville at 904/334-3400, ext. 1284, or me at 222-7500.

Sincerely,

HOPPING BOYD GREEN & SAMS

BY: Douglas S Roberts

Douglas S. Roberts
Post Office Box 6526
Tallahassee, FL 32314
(904) 222-7500

Attachments

cc: Richard T. Donelan, DEP
Mary Marshall, Alachua County Attorney
Cindy S. Price, Asst. General Counsel
Fla. Dept. of Transportation
Charles F. Justice, Exec. Director
North Central Fla. Regional Planning Council

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

IN RE: SITE CERTIFICATION, DEERHAVEN UNIT NO. 2; GAINESVILLE REGIONAL UTILITIES	)	DER CASE NO. PA 74-04

PROPOSED AGREEMENT FOR MODIFICATION OF SITE CERTIFICATION, INCLUDING ADDITIONAL CONDITIONS OF CERTIFICATION, FOR NEW COMBUSTION TURBINE

I.

Gainesville Regional Utilities (GRU) hereby requests a modification of the site certification, including conditions of certification, for Deerhaven Unit No. 2 pursuant to Section 403.516.(1)(b), Florida Statutes (F.S.) and Rule 17-17.211, Florida Administrative Code (F.A.C.). Those provisions authorize the Department of Environmental Protection (DEP) to modify the certification after public notice and opportunity for review by the public and by the parties to the original certification proceeding and upon no objection to the proposed modification being raised by those persons. This agreement for modification addresses the construction and operation of a new 74 megawatt (nominal) simple cycle combustion turbine (CT) to be located within the certified Deerhaven site. In support of this modification, GRU states:

II.

On May 16, 1978, GRU was issued a final Site Certification Order by the Siting Board, pursuant to Chapter 403, Part II, F.S., authorizing the construction and operation of Deerhaven Unit No. 2, subject to the provisions of the certification order and to the conditions of certification included in that order. That certification authorized the construction and operation of a 235 megawatt (MW) electrical generating plant on the Deerhaven site. The site already contained an existing oil and gas-fired generating unit (Unit 1) and two gas turbines. GRU has identified several needed modifications to the certification including additional conditions of certification to allow construction and operation of a new nominal 74 MW natural gas-fired combustion turbine within the certified Deerhaven site.

This modification of site certification is required because the new CT will be located within the previously certified Deerhaven power plant site. Pursuant to the PPSA, issuance of the original certification for the Deerhaven site has vested exclusive authority in the Siting Board for approval of any subsequent activities on the certified Deerhaven site which would otherwise require regulatory approval by a state, regional or local agency. The proposed CT has no steam electric generating capacity greater than 75 MW. Therefore, if this CT were located at a site other than the Deerhaven site, this CT project would not be subject to the PPSA since it is not an "electrical power plant" as defined in the PPSA, section 402.503(12), F.S. Thus, approval of this CT project will be obtained in the form of a modification of the original certification for Deerhaven Unit 2 and not as a separate certification proceeding.

III.

The new CT will be located on a one acre parcel of the existing Deerhaven site, adjacent to the existing combustion turbines on the site. The CT will interconnect to the existing electrical transmission system on the site with no new transmission facilities offsite required to accommodate this unit. The existing natural gas supply line and fuel oil storage tank will serve the new CT. Minimal offsite and onsite impacts will occur, principally due to the development of the small CT project site including stormwater management facilities. No changes to other onsite facilities will be required as a result of the CT project. The principal impact will be to air resources in the area, with the project having only a minimal impact on air quality in the vicinity of the site. The details of the project and its impacts are described in the attached Request for Modification of Site Certification and the separate application for a Prevention of Significant Deterioration (PSD) permit. A copy of that application is included with this request as additional information.

IV.

GRU proposes that additional and modified conditions of certification be imposed as part of the approval of this modification. A proposed set of additional conditions of certification is appended to this request. These conditions address principally the additional air emissions from the CT project and establish appropriate post-certification proceedings for submittal of additional information to jurisdictional regulatory agencies principally DEP, for approval, as appropriate and necessary.

Request For Relief

Accordingly, GRU requests that

1. All parties to the original certification proceeding agree to, or otherwise do not object to, this proposed modification and the attached additional provisions of the certification and the conditions of certification within thirty (30) days of submittal of this proposed Agreement, as provided for in Section 403.516(1)(b), F.S.;

2. Upon no objection being raised by the parties as provided above or by a substantially affected person within forty-five (45) days of public notice of this proposed modification, the Department of Environmental Protection issue an order modifying the terms and conditions of the certification, pursuant to Section 403.516.(1)(b), F.S., and incorporating the proposed additional and modified conditions of certification; and

3. The Department of Environmental Protection grant such other relief as may be appropriate, including necessary additional conditions of certification proposed by agency parties.

Respectfully submitted this 22nd day of March, 1994.

HOPPING BOYD GREEN & SAMS

Douglas S. Roberts
Fla. Bar No. 0559466
123 South Calhoun Street
Post Office Box 6526
Tallahassee, Florida 32314
(904) 222-7500

Attorney for Gainesville
Regional Utilities

CERTIFICATE OF SERVICE

8

I HEREBY CERTIFY that a copy of the foregoing and attachment have been furnished to the following on this 22nd day of March, 1994:

Hamilton S. Oven, Jr., P.E.
Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Richard T. Donelan
Assistant General Counsel
Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Karen Brodeen
Assistant General Counsel
Department of Community Affairs
2740 Centerview Drive
Tallahassee, FL 32399-2100

James V. Antista
General Counsel
Florida Game & Fresh Water Fish Commission
620 South Meridian Street, Room 101
Tallahassee, FL 32399-1600

Rob Vandiver
General Counsel
Michael Palecki
Florida Public Service Commission
101 East Gaines Street
Fletcher Building, Room 212
Tallahassee, FL 32399-0850

Tom Brown
General Counsel
Suwannee River Water Management District
Rt. 3, Box 64
Live Oak, FL 32060

Jane Walker
Florida Defenders of the Environment
10601 N.W. 23rd Ave.
Gainesville, Fla. 32606

Douglas S. Roberts
Attorney

March 21, 1994

Proposed Conditions of Certification
GRU Deerhaven CT #3 Project

AIR

The construction and operation of the Gainesville Regional Utilities Deerhaven Combustion Turbine #3 (DHCT3) shall be in accordance with all applicable provisions of Chapters 17-210 to 297, F.A.C. and 40 CFR Subparts A and GG. The following emission limitations and conditions reflect BACT determinations for the DHCT3. In addition to the foregoing, the Project shall comply with the following conditions of certification as indicated.

A. General Requirements

1. The maximum heat input rates to DHCT3 at ISO conditions (i.e., 59° F, 60% relative humidity and sea level pressure) shall neither exceed 971.1 MMBtu/hr while firing natural gas, 1096.6 MMBtu when firing natural gas in the power augmentation (PA) mode, nor 990.6 MMBtu/hr while firing fuel oil. Heat input will vary depending on ambient conditions and the DHCT3 characteristics. Manufacturer's curves or equations for correction to other ambient conditions shall be provided to DEP at least 90 days before initial compliance testing.

2. The DHCT3 may operate up to 3900 hours per year, of which 2000 hours may be while firing fuel oil and up 390 hours of natural gas firing with power augmentation.

3. Only natural gas (NG) or low sulfur fuel oil shall be fired in the combustion turbine. The maximum sulfur content of the fuel oil shall not exceed 0.05 percent, by weight except that the permittee shall be allowed up to an equivalent of 55 hours of full load operation at ISO conditions using fuel oil with a sulfur content of 0.25 percent by weight. Thereafter, the maximum sulfur content shall not exceed 0.05 percent by weight.

4. Fugitive dust emissions during the construction period shall be minimized by covering or watering dust generation areas.

B. Emission Limits

1. The maximum allowable emissions from the DHCT3, when firing natural gas or low sulfur fuel oil, in accordance with the BACT determination, shall not exceed the following, at ISO conditions based upon the high heating values of the fuels (except during periods of start up, shutdown, malfunction, fuel switching, and load change):

EMISSIONS LIMITATIONS

POLLUTANT	FUEL	BASIS(a)	LB/HR(b)		TPY(c)
NOx	GAS	15 ppmvd(d)	53		40
	GAS w/PA	30 ppmvd(d)	120		23
	Oil	54 ppmvd(e)(d)	213		213
				Total	276
VOC (f)	Gas	2 ppmvw	3		
	Gas w/PA	3 ppmvw	5		
	Oil	5 ppmvw	6		
				Total	9
CO	Gas	15 ppmvd	32		
	Gas w/PA	20 ppmvd	42		
	Oil	30 ppmvd	65		
				Total	97
PM/PM_{10} (f)	Gas		7		
	Gas w/PA		7		
	Oil(g)		15		
				Total	22
SO_2	Gas		26		
	Gas w/PA		30		
	Oil (0.05%) (h)		48		
	Oil (0.25%) (h)		240		
				Total	80
Visible Emissions	Oil	20 percent opacity			

PA - Power Augmentation.

a. The values are the computational basis for the lb/hr numbers, which are the actual emission limitations.

b. Emission limitations in LB/HR are blocked 24-hour averages (midnight to midnight), except for opacity which is based on 6-minute averages. All values, except opacity, are at ISO conditions.

c. Annual emission limits (TPY) are based on the DHCT3 operating at full load for a total of 3900 hours per year, with up to 2000 hours of oil-fired operation and up to 390 hours of natural gas firing with power augmentation, with the remaining hours on natural gas firing.

d. 15 ppmvd/30 ppmvd/54 ppmvd at 15% O_2, not ISO corrected.

e. Fuel oil NO_x emissions are based on full load operation at

ISO conditions and 15 percent oxygen. For fuel oil firing, NO_x levels of 54 ppmvd are based on a fuel bound nitrogen content of 0.030 percent by weight.

f. Exclusive of background concentrations.

g. PM/PM10 emission limitations are exclusive of sulfuric acid mist and sulfates.

h. SO_2 emissions based on a maximum of 0.05 percent sulfur in the fuel oil except that up to an equivalent of 55 hours of full load operation at ISO conditions are authorized using fuel oil with a 0.25% sulfur content by weight. A 95.1% conversion of sulfur is assumed.

2. The following DHCT3 emission controls are tabulated for PSD purposes:

ESTIMATED EMISSIONS

POLLUTANT	METHOD OF CONTROL	Basis (a)
Sulfuric Acid Mist	Natural Gas/No. 2 Fuel Oil (b)	BACT
Inorganic Arsenic	Natural Gas/No. 2 Fuel Oil (b)	(c)
Beryllium	Natural Gas/No. 2 Fuel Oil (b)	(c)
Mercury	Natural Gas/No. 2 Fuel Oil (b)	(c)
Pb	Natural Gas/No. 2 Fuel Oil (b)	(c)

a. Since these pollutants are inherent constituents in the fuel, the basis for control will be by specifying that only natural gas and No. 2 fuel oil can be fired at the facility.

b. Only natural gas or No. 2 fuel oil will be combusted. The No. 2 fuel oil shall have a maximum sulfur content of 0.05% by weight except that the permittee is authorized for up to an equivalent of 55 hours of full load operation at ISO conditions using a fuel oil with 0.25% sulfur content.

c. Below PSD significant emissions level.

3. The permittee will install a dry low NOx combustor on DHCT3 for NOx control when firing natural gas. Control of NOx when firing fuel oil will be accomplished by water injection.

4. Excess emissions from the DHCT3 resulting from start up, shutdown, malfunction, fuel switching, or load change shall be acceptable providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24 hour period unless specifically authorized by the Department for a longer duration.

C. Performance Testing

1. Initial (I) compliance tests shall be performed on the DHCT3 using both fuels. Testing of emissions shall be conducted with the source operating at capacity (maximum heat input rate for the tested operating temperature). This requirement is met if the compliance test is conducted at 90-100% of the permitted capacity achievable for the average ambient air temperature during the test. Although this may result in tests at less than 90% of the maximum permitted heat input under Conditions A.1, above, if the test demonstrates compliance at the lower heat input rate, DHCT3 may be operated at the permitted capacity for the full range of ambient conditions. If it is impracticable to test at capacity, then sources may be tested at less than capacity; in this case subsequent source operation is limited to 110% of the test load until a new test is conducted. Once the unit is so limited, then operation at higher capacities is allowed for no more than fifteen days for purposes of additional compliance testing to regain the rated capacity in the permit, with prior notification to the Department.

Annual (A) compliance tests shall be performed on the DHCT3 with the fuel(s) used for more than 400 hours in the preceding 12-month period. Tests shall be conducted using EPA reference methods in accordance with 40 CFR 60, Appendix A, as adopted by reference in Rule 17-297, F.A.C.:

a. Reference Method 5, 5B, 5F or 17 for PM (I, A, for oil only).

b. Reference Method 9 for VE (I, A for oil only).

c. Reference Method 10 for CO (I, A).

d. Reference Method 20 for NOx (I, A).

e. Reference Method 18 for VOC (I, A).

f. ASTM D 4294 (or equivalent) for sulfur content of distillate oil (I,A), which can be used for determining SO_2 and $H2SO_4$ emissions annually.

g. ASTM D 1072-80, D 3031-81, D 4084-82, or D

3246-81 (or equivalent) for sulfur content of natural gas (I, and A if deemed necessary by DEP). Alternatively, natural gas supplier data for sulfur content may be submitted.

Other DEP approved methods may be used for compliance testing after prior departmental approval.

2. Sulfur and nitrogen content and lower heating value of the fuel being fired in the combustion turbines shall be based on a weighted 12 month rolling average from fuel delivery receipts or other records supplied by the fuel supplier. The records of fuel oil usage shall be kept by GRU for a two-year period for regulatory agency inspection purposes. For sulfur dioxide, periods of excess emissions shall be reported if the fuel oil being fired in the gas turbine exceeds 0.05 percent sulfur except for up to an equivalent of 55 hours of full load operation using 0.25% sulfur oil.

D. Monitoring Requirements

1. CEMS data shall be recorded and reported in accordance with 40 CFR 60 and 40 CFR 75 for NOx emissions. Periods of start up, shutdown, fuel switching, malfunction, and load change shall be recorded.

2. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

E. Notification, Reporting and Recordkeeping

1. To determine compliance with the natural gas and fuel oil firing heat input limitation, the permittee shall maintain daily records of natural gas and fuel oil consumption for the turbine. All records shall be maintained for a minimum of two years after the date of each record and shall be made available to representatives of the Department upon request.

2. The project shall comply with all the applicable requirements of Chapter 17, F.A.C., and 40 CFR 60 Subparts A and GG. All notifications and reports required by this specific condition shall be submitted to the Department's Air Program, within the Northeast District office. Performance test results shall be submitted within 45 days of completion of such test.

4. The following protocols shall be submitted to the Department's Air Program, within the Northeast District office for approval;

a. CEMS - The Federal Acid Rain Program requirements of 40

CFR 75 shall apply when those requirements become effective within the state.

b. Performance Test Protocol - At least 90 days prior to conducting the initial performance tests required by this permit, The permittee shall submit to the Department's Air Program, within the Northeast District office, a protocol outlining the procedures to be followed, the test methods and any differences between the reference methods and the test methods proposed to be used to verify compliance with the conditions of this permit. The Department shall approve the testing protocol provided that it meets the requirements of this permit.

c. The permittee shall notify the Department at least 15 days prior to conducting compliance testing, in accordance with Rule 17-297.340, FAC.

F. Modifications

The permittee shall give written notification to the Department when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change.

Florida Department of

Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

February 11, 1994

Ms. Yolanta E. Jonynas
Senior Environmental Engineer
Gainesville Regional Utilities
P.O. Box 147117, Station A136
Gainesville, Florida 32614-7117

Re: Gainesville Regional Utilities
Deerhaven Generating Station (PA 74-04)
74 MW Simple Cycle Combustion Turbine
Preliminary Air Quality Modeling Results and Monitoring Exemption Request

Dear Ms. Jonynas:

The Department has reviewed your Ambient Air Monitoring Exemption request and your subsequently submitted Preliminary Air Quality Modeling Results. The Department has the following comments:

1. Based on the information provided in the Monitoring Exemption Request, the Department concurs that the maximum predicted impacts of the proposed combustion turbine are below the monitoring significance levels specified in F.A.C. Rule 17-212.400(3)(e) for the following PSD significant pollutants: SO_2, PM, NO_x, CO, Be, Hg, and fluorides. Therefore, preconstruction monitoring will not be required for these pollutants. In addition since the project's projected VOC emissions are less than 100 tons per year, preconstruction monitoring will not be required for ozone.

2. Based on the results of your preliminary air quality modeling for the proposed combustion turbine alone, the Department agrees that off-site impacts from the project will not be significant and that multiple source modeling is not required for either the near site Class II PSD increment/ambient standards analysis or the long distance Class I PSD increment analysis for the following PSD significant pollutants: SO_2, PM, CO, and NO_x.

3. However, even though the project's maximum predicted air quality impacts (when using 0.05% sulfur or natural gas) are less than the National Park Service's recommended significance levels for SO_2, PM, and NO_2, you will still have to do an air quality related values (AQRV) analysis for these pollutants and all other PSD

significant pollutants for both the Chassahowitzka and Okefenokee National Wilderness Areas. The AQRV analysis evaluates potential effects of the project on vegetation, wildlife, soils, aquatic resources, and visibility. Depending upon the project's predicted impacts for each pollutant, the analysis may, require at the simplest level only a literature review or at the most complex level a deposition analysis using MESOPUFF II in addition to a literature review. Also for determining impacts on PSD Class I areas, the Department follows the recommendations of the Interagency Workgroup on Air Quality Modeling (IWAQM). These recommendations are contained in the "Interagency Workgroup on Air Quality Modeling (IWAQM) Phase I Report: Interim Recommendation for Modeling Long Range Transport and Impacts on Regional Visibility (EPA-454/R-93-015). This document can be downloaded from the EPA's Support Center for Regulatory Air Models Bulletin Board System (SCRAM BBS).

If you have any further modeling questions, please call Cleve Holladay at 904-488-1344.

Sincerely,

C. H. Fancy
Chief
Bureau of Air Regulation

CHF/cgh

cc: Buck Oven, FDEP
Tom Rogers, FDEP
Teresa Heron, FDEP
Doug Fulle, EBASCO

EBASCO

January 21, 1993

Mr. Cleve Holladay
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32301

RECEIVED

JAN 24 1994

Bureau of
Air Regulation

Dear Mr. Holladay:

Subject: Gainesville Regional Utilities
Deerhaven Combustion Turbine Addition
Air Quality Modelling Runs

I understand that in a conversation with Ms. Yolanta Jonynas of GRU you asked for a disk containing the input and output files of the ISC2 model runs which were made in support of the analysis transmitted to FDEP in a letter from GRU dated December 27, 1993. Ms. Jonynas has asked that I to transmit the disk which you requested directly to you.

The attached disk contains the input and output files which support the Class I Area analysis contained in the December 27, 1993 letter. The other portion of the analysis, dealing with the impacts in the site vicinity, are contained on the disks previously sent to you in support of the Monitoring Exemption Request, dated November 24, 1993. A complete listing of the input and output files on all disks is also enclosed.

Please call me at (404) 662- 2377 should you have any questions on this material.

Very truly yours,

Douglas J. Fulle
Regional Manager, Air Quality

attachment

djf

cc. Y. Jonynas(GRU)
D. Beck(GRU)
D. Roberts(HBGS)
T. Putman
File 326

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning

December 27, 1993

RECEIVED

DEC 29 1993

Division of Air Resources Management

Mr. Hamilton S. Oven
Office of Siting Coordination
Florida Department of Environmental Protection
3900 Commonwealth Blvd., Suite 953
Tallahassee, FL 32399-3000

Re: Gainesville Regional Utilities
Deerhaven Generating Station (PA 74-04)
74 MW Simple Cycle Combustion Turbine
Preliminary Air Quality Modelling Results

Dear Mr. Oven:

The air quality modelling protocol submitted for this project and approved by the Department indicated that preliminary air quality modelling would be conducted for the proposed project alone and projected impacts compared with various "significance levels" in order to determine whether additional air quality impact assessments (i.e., multiple source modelling) would be needed. This letter provides the results of the preliminary modelling and requests Department concurrence that multiple source modelling is not needed to support the Modification to Certification Request/PSD Application.

As indicated in the modelling protocol, worst case load and worst case temperature analyses were conducted for the proposed combustion turbine (CT) on the worst case fuel - No. 2 fuel oil. Based on these analyses, a series of worst case combinations of CT load and ambient temperature were determined for the various averaging times associated with the PSD Class II increments and ambient standards. These worst case combinations were identified in the monitoring exemption request submitted to you on November 24, 1993. CT emissions information and recent No. 2 fuel oil data have been refined since the monitoring exemption request was prepared and these more recent data have been used in the significant impact area analyses described in this letter.

Class II Area Impacts

In order to determine the significant impact areas in the vicinity of the proposed CT for Class II PSD purposes, the worst case load and temperature combinations were analyzed for all five years of meteorological data (Gainesville/Tampa 1985-1989). CT emission rates appropriate for the various temperature/load combinations and consistent with what will be proposed as BACT in the permit application were used in the analysis. The emission rates for sulfur dioxide (SO_2) were based upon a blend of the 187,000 gallons of 0.46% S fuel currently in the on-site tank and a 200,000 gallon batch of 0.05% S fuel oil which has been purchased to add to the tank. For annual average emission rates for all pollutants, the short-term maximum rates were scaled down to a lower number consistent with the maximum hours (3,900 hours) of CT operation which will be requested in the permit application. The results of this analysis are presented in Attachment 1. As indicated, the maximum predicted impacts (<u>highest</u> not highest, second-highest) values are below the Class II significance values defined in Table C-4 of the Draft New Source Review Workshop Manual. Thus, the off-site impacts from the project will not be "significant," and no further air quality impact assessments (i.e., multiple source modelling) in the site vicinity should be needed.

Class I Area Impacts

With respect to Class I PSD areas, a separate analysis for distant receptors was conducted using emissions and stack parameters consistent with expected worst case conditions - full load (100%), low temperature (20°F), fuel oil operation. A maximum of 3,900 hours of CT operation and the blended fuel oil sulfur content of 0.25% were assumed for the initial analysis. Receptor locations for the Class I areas were obtained from the Department. The results of the analysis are presented in Attachment 2. As indicated, the maximum (again <u>highest</u> rather than highest, second-highest) impacts based on a five year analysis are below both the EPA(Virginia) and NPS significance values for particulate matter (PM_{10}) and nitrogen dioxide (NO_2). Maximum SO_2 impacts are above the EPA and NPS significance levels, however. For SO_2, using a maximum of 2,000 hours per year of <u>fuel oil operation</u> (which is the maximum amount of fuel oil operation which will be applied for in the application), the predicted annual impacts fall to very close to the NPS significance values, but the maximum predicted short-term impacts are still above the NPS significance values. However, by using the very low sulfur (0.05%) fuel which will ultimately be used for the CT, the maximum predicted impacts fall below the NPS significance values, as indicated in Attachment 2. This implies that the impacts of the proposed project on the Class I areas will be "insignificant" when firing natural gas or very low sulfur fuel oil, and that no further air quality Class I increment consumption assessments (i.e., multiple source modelling) should be necessary for these Class I areas.

Please note that although the application will contain a request to use the existing blend of fuel oil stored in the on-site tank, any new oil purchased for the proposed CT will be the very low sulfur oil used in the final portion of this analysis. The supply of on-site blended fuel (387,000 gallons) could be used up in about 52 hours of continuous full load, low temperature operation. Thus, for the purposes of determining the need for multiple source modelling for Class I PSD areas, it is reasonable to use the very low sulfur fuel oil which will be the ultimate fuel for the proposed CT when it is not burning natural gas, the primary fuel.

Please review the attached information and provide us with your concurrence that further air quality modelling is not required for either the near site Class II PSD increment/ambient standards analysis or the long distance Class I PSD increment analysis. Should you have any questions on this analysis, please call me at (904) 334-3400 ext. 1284.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Senior Environmental Engineer

YEJ:djf
Enclosures

xc. Doug Beck
Doug Fulle, Ebasco
Doug Roberts, HBGS
Tom Rogers, FDEP
DHGT3

SUMMARY OF MAXIMUM OFF-SITE IMPACTS VERSUS CLASS II PSD SIGNIFICANCE VALUES

Pollutant	Averaging Time	Emission Rate (g/s)	Ambient Temperature (°F)	CT Load (%)	Year	Normalized Impact ($\mu g/m^3$)	Maximum Impact ($\mu g/m^3$)	Class II Significance Value ($\mu g/m^3$)
SO_2	Annual	12.5	20	80	85	.00262	.03275 OK	1
					86	.00228	.02850	
					87	.00254	.03175	
					88	.00257	.03213 OK	
					89	.00245	.03063 OK	
	24-Hour	28.1 OK	20	80	85	.03910	1.0987 OK	5
					86	0.3643	1.0237	
					87	.03986	1.1201	
					88	.04025	1.1310 OK	
					89	.05223	1.4677 OK	
	3-Hour	20.7	75	60	85	.20018	4.1437	25
					86	.18534	3.8365	
					87	.19481	4.0326	
					88	.17011	3.5213	
					89	.23693	4.9045	
PM_{10}	Annual	.085	95	60	85	.00323	.00275	1
					86	.00279	.00237	
					87	.00301	.00256	
					88	.00318	.00270	
					89	.00306	.00260	
	24-Hour	1.9 OK	95	60	85	.04638	.08812	5
					86	.04195	.07971	
					87	.04964	.09432 OK	
					88	.04949	.09403	
					89	.06108	.11605	

SUMMARY OF MAXIMUM OFF-SITE IMPACTS VERSUS CLASS II PSD SIGNIFICANCE VALUES

Pollutant	Averaging Time	Emission Rate (g/s)	Ambient Temperature (°F)	CT Load (%)	Year	Normalized Impact ($\mu g/m^3$)	Maximum Impact ($\mu g/m^3$)	Class II Significance Value ($\mu g/m^3$)
CO	8-Hour	7.9	20	60	85	.10005	.79040	500
					86	.08489	.67063	
					87	.12073	.95377	
					88	.08630	.68177	
					89	.12577	.99358	
	1-Hour	7.3	75	60	85	.45575	3.3270	2000
					86	.46655	3.4058	
					87	.46367	3.3848	
					88	.41993	3.0655	
					89	.71080	5.1888	
NO_2	Annual	11.1	20	80	85	.00262	.02908	1
					86	.00228	0.2531	
					87	.00254	0.2819	
					88	.00257	.02853	
					89	.00245	.02720	

Note: Annual emission rates based on 3,900 hours/year operation.
SO_2 emission rates based on 0.25% S fuel oil.

ATTACHMENT 2

SUMMARY OF MAXIMUM CLASS I AREA IMPACTS AT 20°F 100% LOAD ON FUEL OIL OK						
Pollutant	Emissions (g/s)	Averaging Period	Maximum Concentration ($\mu g/m^3$) Chassahowitzka	Maximum Concentration ($\mu g/m^3$) Okefenokee	EPA (Virginia) Significance Values ($\mu g/m^3$)	NPS Significance Values ($\mu g/m^3$)
Based on 3,900 Hours/Year (.445 of Year) of .25% S Fuel Oil:						
SO_2	14.9 33.6 33.6	Annual 24 3	0.00522 ok 0.31954 OK 1.52443 OK	0.00522 0.342380 OK 1.34299 OK	0.1 0.275 1.23	.0025 .07 .48
PM_{10}	0.85 1.9	Annual 24	0.00030 OK 0.01807 OK	0.00030 OK 0.01936 OK	.27 1.35	.08 .33
NO_2	13.3	Annual	0.00466 OK	0.00466 OK	0.1	.025
Based on 2,000 Hours/Year (.228 of Year) of .25% S Fuel Oil:						
SO_2	7.66 33.6 33.6	Annual 24 3	0.00268 OK 0.31954 OK 1.52443 OK	0.00268 OK 0.34238 OK 1.34299 OK	0.1 0.275 1.23	.0025 .07 .48
Based on 2,000 Hours/Year (.228 of Year) of .05% S Fuel Oil:						
SO_2	1.52 6.68 6.68	Annual 24 3	1989 0.00053 OK 0.06353 OK 0.30307 OK	0.00053 OK 0.06807 OK 0.26700 OK	0.1 0.275 1.23	.0025 .07 .48
Note: Annual emission rates are scaled based on 3,900 or 2,000 hours per year of operation. SO_2 emission rates based on expected fuel oil mix (.25% S) and future oil (.05% S).						

.03997

Pretty file

I N T E R O F F I C E   M E M O R A N D U M

Date: 01-Nov-1993 03:54pm
From: Douglas Outlaw TAL
OUTLAW_D
Dept: Air Resources Manage
Tel No: 904/488-1344
SUNCOM: SC 278-1344

TO: Hamilton Buck Oven TAL (OVEN_H)

CC: Preston Lewis TAL (LEWIS_P)
CC: Syed Arif TAL (ARIF_S)

Subject: GRU Minutes of Sept 22, 1993, Meeting

I have noted several comments on the minutes submitted by GRU for the Deerhaven Generating Station. The comments are:

a. Paragraph 3 - The Department agreed that SNCR, not SCR, was not technically feasible but would need to be verified in the application. An economic analysis for SCR will need to be included as a part of the BACT application.

b. Paragraph 4 - Use of the fuel oil currently stored on site was discussed during the meeting with GRU and it was agreed that fuel oil issues would require further discussion. GRU did indicate that the fuel oil currently stored on site could be used in other units; however, no discussion of NOx emissions for the proposed CT in the 80-85 ppmvd range for fuel oil firing occurred during the meeting. GRU indicated that the fuel bound nitrogen content in the fuel stored on site had been tested at 0.1 per cent, by weight, but were planning to collect another sample for a new analysis.

c. The Department did suggest that GRU consider a limitation on the hours the CT is fired with fuel oil but also stated that that the number of hours allowed can significantly impact the economic analysis for the BACT determination.

Florida Department of
Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

October 26, 1993

Ms. Yolanta E. Jonynas
Senior Environmental Engineer
Gainesville Regional Utilities
P.O. Box 147117, Station A136
Gainesville, Florida 32614-7117

Dear Ms. Jonynas:

I have reviewed the revised air quality modeling protocol provided with your October 20 letter to Mr. Hamilton Oven. This protocol is acceptable. If you have any further questions regarding the required air quality analysis please call me at 904/488-0114.

Sincerely,

Thomas G. Rogers

Thomas G. Rogers
Administrator

TGR/tr

cc: H. Oven
P. Lewis

GRU

GAINESVILLE REGIONAL UTILITIES

Strategic Planning

October 19, 1993

Mr. Hamilton Oven, Siting Coordinator
Florida Department of Environmental Protection
3900 Commonwealth Blvd., Suite 953
Tallahassee, FL 32399

RE: Gainesville Regional Utilities
Deerhaven Generating Station (PA 74-04)
74 MW Simple Cycle Combustion Turbine Project

Dear Mr. Oven:

Enclosed are the minutes of our September 22, 1993 meeting to discuss the 74 MW simple cycle combustion turbine which Gainesville Regional Utilities is proposing to locate at the Deerhaven Generating Station.

The modelling protocol has been revised to incorporate the Department's comments and will be submitted under separate cover for your review and approval.

Please call me at (904) 334-3400 Ext. 1284 if you have any questions.

Sincerely,

Yolanta E. Jonynas

Yolanta E. Jonynas
Sr. Environmental Engineer

Enclosure

xc: Doug Beck (w/o enc)
Martin Costello, FDEP
Teresa Heron, FDEP
Cleve Holladay, FDEP
Doug Outlaw, FDEP
Doug Roberts, HBGS
Tom Rogers, FDEP
DHGT3

OVEN1093.y13

(904) 334-3400 ext. 1261 P.O. Box 147117, Station A136, Gainesville, Florida 32614-7117 Fax: (904) 334-3151

MINUTES OF MEETING

Date: September 22, 1993

Location: FDEP Offices/Tallahassee

Subject: Deerhaven Combustion Turbine Project
Environmental Permitting Plans

Attendees:
Doug Beck, GRU
Yolanta Jonynas, GRU
Doug Fulle, EED
Buck Oven, FDEP
Darrel Graziani, EED
Doug Outlaw, FDEP
Teresa Heron, FDEP
Doug Roberts, HBGS
Tom Rogers, FDEP
Cleve Holladay, FDEP
Martin Costello, FDEP

Purpose: The purposes of the meeting were to: (1) bring the FDEP personnel up to speed on GRU's plans for the project; (2) provide FDEP with a description of the proposed modification to certification request package; (3) go over the air quality modelling protocol which had been previously submitted; (4) discuss potential BACT emission rates; (5) discuss the potential for fuel oil firing (both new very low sulfur oil and existing low sulfur oil); and (6) discuss issues related to the monitoring of flow in the combustion turbine stack.

A summary of the meeting follows:

1. After initial introductions, Tom Rogers indicated that Cleve Holladay will probably be the meteorologist assigned to the application and Teresa Heron indicated that she will probably be assigned to the permit and Doug Outlaw will be involved in the BACT portion of the application. Buck Oven confirmed that the project would be treated as a modification to certification. Doug Roberts provided copies of the modification to certification package description to the meeting participants and D. Fulle summarized its contents. Buck Oven's initial reaction to the document was favorable, although it was recognized that a formal review of the submittal would need to await a more thorough review.

2. Doug Fulle asked for FDEP's comments on the modelling protocol. Tom Rogers indicated that the overall modelling approach was acceptable, but that there were a few specific comments. They want to see all 189 air toxics listed in the CAAA90 addressed, not just the criteria pollutants; however, multiple source modelling will be required only for those criteria pollutants with significant off-site impacts. The IWAQM recommendations

regarding determining impacts on the Class I PSD areas will need to be followed, and impacts on both Class I areas rather than just the nearest one will be required. Similarly, for visibility, impacts on both Class I areas will need to be evaluated. Tom Rogers indicated that the need for or lack of need for an AQRV analysis will need to be determined after consultations with the Park Service rather than being determined by the level of impacts versus the NPS significance values. FDEP offered to be involved in any discussions with the NPS on this issue. Tom Rogers confirmed that the Gainesville/Tampa meteorological data set supplied by FDEP should be used in the analysis as opposed to a Gainesville/Waycross data set. He further confirmed that flat terrain can be used in the analyses.

3. Doug Fulle described some of the BACT issues which GRU wanted to get some initial feedback on, including the 15 ppmvd emission level for NOx when firing natural gas. Three cases were discussed: (1) dry low NOx combustor when firing gas; (2) water injection for power augmentation when firing gas; and (3) water injection when firing fuel oil. The fact that the unit is being built at the GE factory in 1993 and will be in commercial operation in 1995 was stressed to emphasize the differences in schedule between GRU's project and a number of others whose applications are before FDEP now but whose commercial operation is not expected before 1997 or 1998. There was no adverse reaction by FDEP to the 15 ppmvd level as a potential BACT level for NOx on gas. It was agreed that while we will need to verify the lack of technical feasibility of SCR for this simple cycle application, we will not need to include an economic analysis of SCR. FDEP requested that the emissions data supplied with the application should be for both ISO conditions and for a low temperature case (ie. 20 F).

4. Doug Fulle indicated that there were two fuel related issues for discussion: (1) any expected limitations on fuel oil firing in general, and (2) any limitations on firing the No. 2 fuel oil existing on site until as this supply is depleted. Emissions of NOx with water injection for new oil would probably be in the range of 42-48 ppmvd (depending upon fuel bound nitrogen) and for the existing on-site oil in the 80-85 ppmvd range (due to its high fuel bound nitrogen content). Doug Beck indicated that the existing oil would be burned on site anyway since the existing CTs are permitted to burn it, and it would make sense to GRU to burn it in the newer, more efficient unit to get rid of it sooner. This would also allow for maintaining only a single fuel oil storage tank for the No. 2 fuel oil. Doug Outlaw indicated that FDEP would be expecting to include some kind of a limitation on the amount of fuel oil firing but did not indicate how many hours would be acceptable to the Department. He also indicated that they might be willing to accept the firing of the existing on-site fuel oil if there were a commitment from GRU that only very low sulfur oil would be purchased to replenish the existing supply. It was agreed that the fuel oil issues will require further discussion.

5. Doug Beck talked about GRU's plans for CEMS for the CT. He indicated that GRU would prefer to have a CEMS for SO2 as opposed to using the alternative method allowed by the 40 CFR 75 regulations since they will already have a CEMS for NOx for the CT and a comprehensive CEMS program for the whole Deerhaven site. However, they are aware of a problem with measuring flow in the CT exhaust stack (required for SO2 determination) due

to the turbulence and may need to seek approval of an alternative flow measurement technique or location. There may also be a problem with the use of Method 2 for flow determination in the stack sampling/compliance test due to this same turbulence problem. Martin Costello and Doug Outlaw advised that the procedure to get these issues resolved would be to write a letter to Mike Harley of FDEP requesting approval of an alternative monitoring/measurement location or technique which would include explanations from GE on the problem.

6. Tom Rogers added a couple of additional points on the modelling. First, we should use a 0.25 km spacing on receptors on our coarse grid in areas expected to have the maximum impacts (to be determined by SCREEN or screening runs of ISCST) rather than the 0.5 km spacing which we had proposed. Second, we should assume 10 grains of sulfur per hundred standard cubic feet of natural gas.

7. Action items

- Doug Fulle to prepare meeting minutes.
- GRU to have their existing oil's fuel bound nitrogen content reanalyzed.
- GRU to get discuss the flow measurement method problem with GE and prepare a letter to Mike Harley of FDEP requesting approval for alternative methods.
- Ebasco Environmental to revise the modelling protocol per the discussions for resubmittal to FDEP.
- Upon completion of preliminary modelling, GRU/Ebasco to contact FDEP about discussing the need for an AQRV analysis with the federal land manager for the Class I PSD areas.
- FDEP (Buck Oven) to review and provide comments to GRU on the modification to certification package description.

djf

Check Sheet

Company Name: Gainesville Regional Utilities
Permit Number:
PSD Number: ~~[illegible]~~ PSD FL-212
Permit Engineer:

Application:

- ☐ Initial Application
  - ☑ Incompleteness Letters
  - ☑ Responses
  - ☐ Waiver of Department Action
  - ☐ Department Response
  - ☐ Other

Cross References:
- ☑ PA 74-04
- ☐
- ☐

Intent:

- ☑ Intent to Issue
- ☑ Notice of Intent to Issue
- ☑ Technical Evaluation
- ☐ BACT or LAER Determination
- ☑ Unsigned Permit
- Correspondence with:
  - ☑ EPA
  - ☐ Park Services
  - ☐ Other
- ☑ Proof of Publication
  - ☐ Petitions - (Related to extensions, hearings, etc.)
  - ☐ Waiver of Department Action
  - ☐ Other

Final
Determination:

- ☑ Final Determination
- ☑ Signed Permit
- ☐ BACT or LAER Determination
  - ☐ Other

Post Permit Correspondence:

- ☐ Extensions/Amendments/Modifications
- ☐ Other

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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.

I also wish to receive the following services (for an extra fee):
1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Michael L. Kurtz Gen. Mgr.
Gainesville Regional Utilities
P.O. BOX 147117-Station A-134
Gainesville, Fl
32614-7117

4a. Article Number
Z 311 902 936

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

7. Date of Delivery
APR 13 1995

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form **3811**, December 1991 ★U.S. GPO: 1993—352-714 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

Z 311 902 936

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

PS Form **3800**, March 1993

Sent to Michael Kurtz	
Street and No. GRU	
P.O., State and ZIP Code Gainesville, Fl	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date PSD-F1-212 4-11-95	

Department of Environmental Regulation

Routing and Transmittal Slip

To: (Name, Office, Location)

1. Clair Fancy
2. Air Regulations
3. Magnolia Plaza
4. MS 5500

Remarks:

~~Patty~~

1. ~~Teresa~~
2. Kanani

I believe the PSD is already issed, if not it needs to be

The PSD permit was issued 4/11 Please pass on to Teresa FYI & then to Kanani for filing thanks Patty

RECEIVED

APR 10 1995

Bureau of Air Regulation

From
Perry

Date 4/7/95

Phone 1-9642

NO. 8895

THE GAINESVILLE SUN
Published Daily and Sunday
GAINESVILLE, FLORIDA

STATE OF FLORIDA
COUNTY OF ALACHUA

Before the undersigned authority personally appeared ....Naomi Williams-Jordan....

who on oath says that he/she is ...Classified Assistant Mgr.... of THE GAINESVILLE SUN, a daily

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

....Notice of Intent....

in the matter of ....

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

....December 24,.... 19..94....

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 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

..4.... day of Jan A.D., 19..95

Martha A. Pattison

(Seal) Notary Public

Naomi Williams-Jordan

MARTHA A. PATTISON
MY COMMISSION EXPIRES
APRIL 8, 1998
#CC 357902
Bonded thru
Troy Fain-Insurance
NOTARY PUBLIC, STATE OF FLORIDA

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION NOTICE OF INTENT TO ISSUE PERMIT PSD-FL-212

The Department of Environmental Protection (Department) gives notice of its intent to issue a PSD permit to the Gainesville Regional Utilities (GRU) to construct a 74 MW simple cycle combustion turbine at GRU's existing facility. The facility is located off US 441 North in Alachua County, Florida. The project is subject to review under the Prevention of Significant Deterioration (PSD) regulations for the following pollutants: sulfur dioxide, nitrogen oxides, sulfuric acid mist and particulate matter. A determination of Best Available Control Technology (BACT) was required for these pollutants. The maximum predicted increases in ambient sulfur dioxide, nitrogen dioxide, and particulate matter concentrations due to this project are all less than the respective PSD Class I and II significant impact levels; thus, no PSD increment consumption was calculated for this project. The Department is issuing this intent to issue for the reasons stated in the Technical Evaluation and Preliminary Determination.

A person whose substantial interests are affected by the Department's proposed permitting decision may petition for an administrative proceeding (hearing) in accordance with Section 120.57, Florida Statutes (F.S.). The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, within 14 days of publication of this Notice. Petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. Failure to file a petition within this time period shall constitue a waiver of any right such person may have to request an administrative determination (hearing) under Section 120.57, F.S.

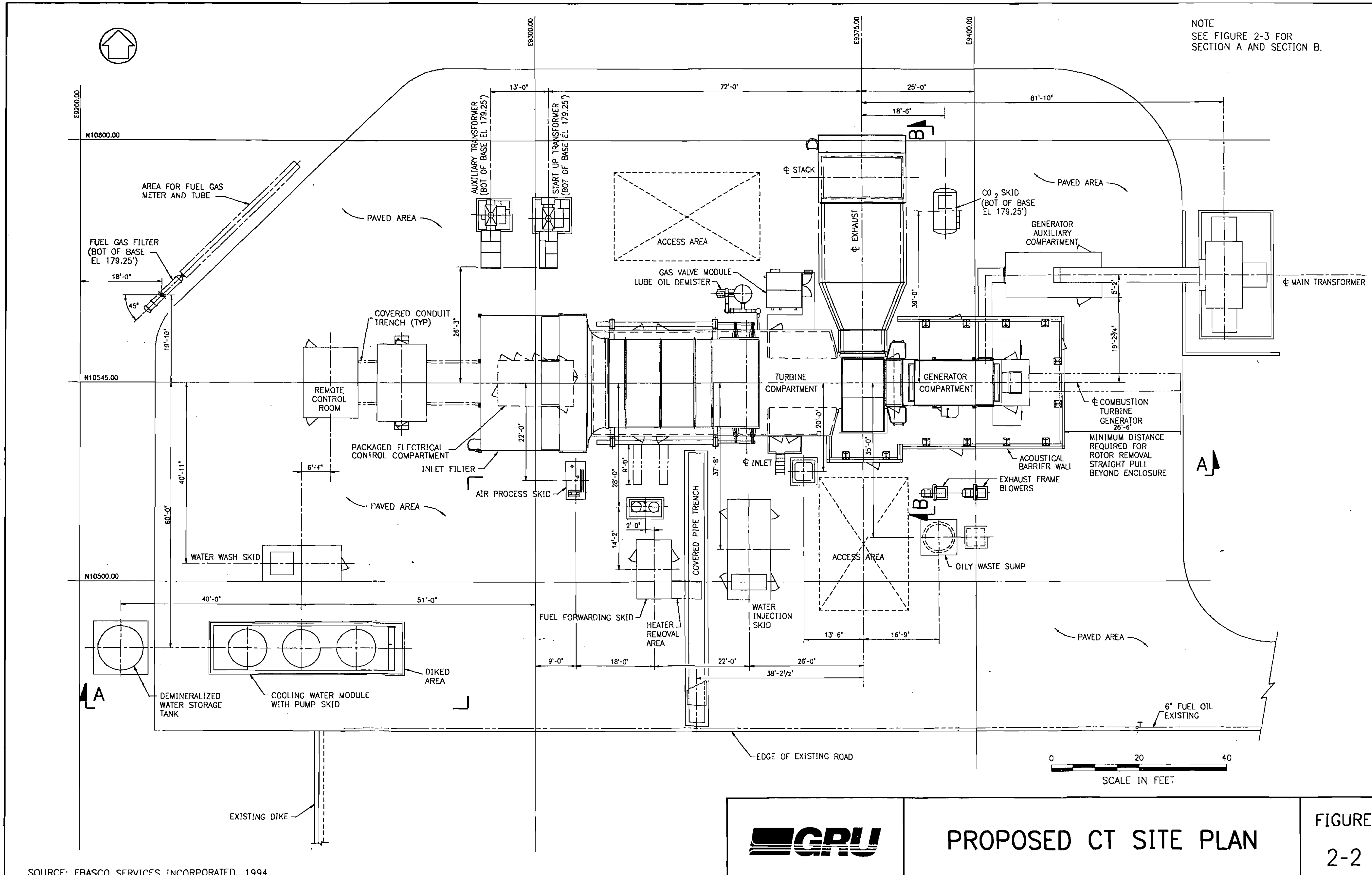
The Petition shall contain the following information: (a) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department Permit File Number and the county in which the project is proposed; (b) A statement of how and when each petitioner received notice of the Department's action or proposed action; (c) A statement of how each petitioner's substantial interests are affected by the Department's action or proposed action; (d) A statement of the material facts disputed by Petitioner, if any; (e) A statement of facts which petitioner contends warrant reversel or modification of the Department's action or proposed action; (f) A statement of which rules or statutes petitioner contends require reversal or modification of the Department's action or proposed action; and (g) A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Department's action or proposed action.

If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, 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 decision of the Department with regard to the application have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 14 days of publication of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Section 120.57, F.S., and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-5.207, Florida Administrative Code.

The Application is available for public inspection during normal business hours, 8:00 am to 5:00 pm, Monday through Friday, except legal holidays, at: Department of Environmental Protection
Bureau of Air Regulation
111 S. Magnolia Drive, Suite 4
Tallahassee, Florida 32301
Department of Environmental Protection
Northeast District
7825 Baymeadows Way Suite B200
Jacksonville, Florida 32256-7577
Department of Environmental Protection
Northeast District Branch Office
5700 Southwest 34th Street, Suite 1204
Gainesville, Florida 32608

Any person may send written comments on the proposed action to Mr. John Brown at the Department's Tallahassee address. All comments received within 30 days of the publication of this Notice will be considered in the Department's final determination.

Further, a public hearing can be requested by any person(s). Such requests must be submitted within 30 days of this Notice.
(8895) 12:24



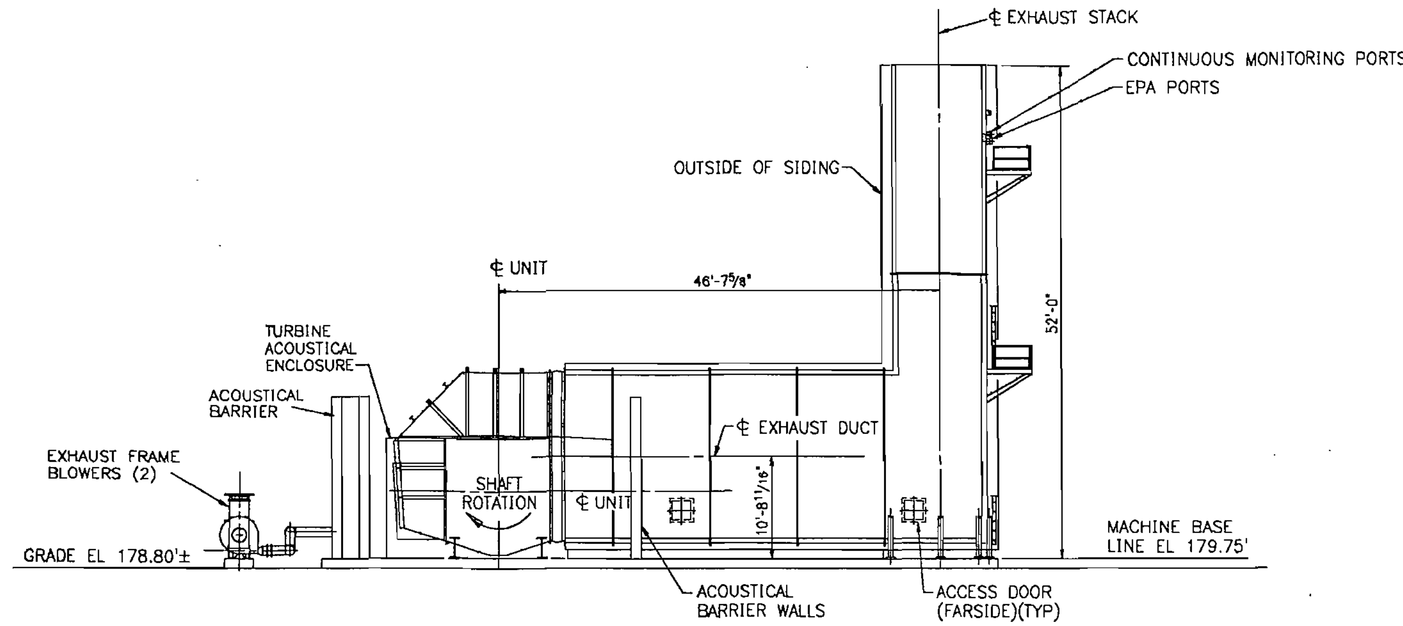
SOURCE: EBASCO SERVICES INCORPORATED, 1994

PLOT DATE FEBRUARY 25, 1994 FILENAME C:\GRU-4124\FIG-2-2.DWG

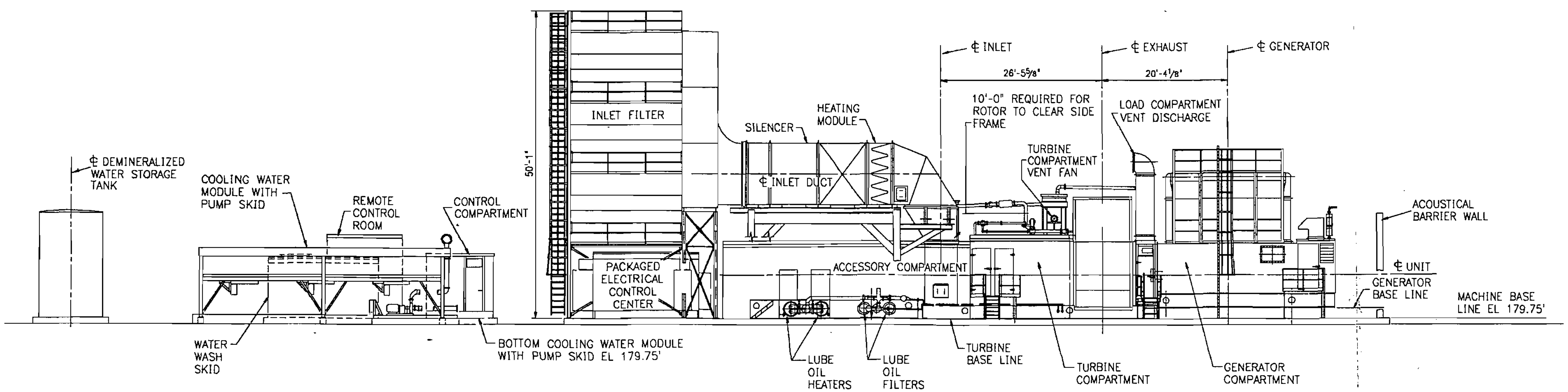
GRU

PROPOSED CT SITE PLAN

FIGURE 2-2



SECTION B
FIGURE 2-2



SECTION A
FIGURE 2-2

0 10 20 40
0 5 10 15 20
SCALES IN FEET

PLOT DATE FEBRUARY 25, 1994 FILENAME C:\GRU-4124\FIG-2-3.DWG

SOURCE: EBASCO SERVICES INCORPORATED, 1994

GRU

PROPOSED CT SITE PROFILE

FIGURE 2-3

Is your RETURN ADDRESS completed on the reverse side?

SENDER:
- Complete items 1 and/or 2 for additional services.
- Complete items 3, and 4a & b.
- 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.

I also wish to receive the following services (for an extra fee):

1. ☐ Addressee's Address
2. ☐ Restricted Delivery

Consult postmaster for fee.

3. Article Addressed to:
Mr. Michael L. Kurtz
General Manager for Utilities
Gainesville Regional Utilities
P. O. Box 147117 - Station A-134
Gainesville, FL 3261407117

4a. Article Number
P 872 562 688

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

7. Date of Delivery
DEC 21 1994

5. Signature (Addressee)

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

6. ~~Signature~~ (Agent)

PS Form **3811**, December 1991 ☆U.S. GPO: 1992—323-402 **DOMESTIC RETURN RECEIPT**

Thank you for using Return Receipt Service.

P 872 562 688

Receipt for Certified Mail
No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to Mr. Michael L. Kurtz, GRU	
Street and No. P. O. Box 147117 Sta. A-134	
P.O., State and ZIP Code Gainesville, FL 32614-7117	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 12-19-94 Permit: PSD-FL-212	

PS Form 3800, JUNE 1991

[BOOTWELL-B] SITE CERTIFICATION
1651
Gainesville Conditions of Certification

GAINESVILLE REGIONAL UTILITIES
Conditions of Certification
PA 74-04 - PSD-FL-212

AIR

The construction and operation of ~~the~~ The Gainesville Regional Utilities Deerhaven Combustion Turbine #3 (DHCT3) shall be in accordance with all applicable provisions of Chapters 17-210 to 297, F.A.C. and 40 CFR Subparts A and GG. The following emission limitations and conditions reflect BACT determinations for the DHCT3. In addition to the foregoing, the Project shall comply with the following conditions of certification. ~~as indicated.~~

General operating Requirements

1. The maximum heat input rates to DHCT3 at ISO conditions (i.e., 59° F, 60% relative humidity and sea level pressure) shall not exceed 971.1 MMBtu/hr while firing natural gas, nor 990.6 MMBtu/hr while firing fuel oil. Heat input will vary depending on ambient conditions and the DHCT3 characteristics. Manufacturer's curves or equations for correction to other ambient conditions shall be provided to DEP Department of Environmental Protection at least 90 days before initial compliance testing.

2. The DHCT3 may operate up to 3900 hours per year, NOT TO EXCEED ~~of which~~ 2000 hours ~~may be~~ while firing fuel oil.

3. Only natural gas (NG) or low sulfur fuel oil shall be fired in the combustion turbine. The maximum sulfur content of the fuel oil shall not exceed 0.05 percent, by weight except that the permittee shall be allowed up to an equivalent of 55 hours of full load operation at ISO conditions using fuel oil with a sulfur content of 0.25 percent by weight. Thereafter, the maximum sulfur content shall not exceed 0.05 percent by weight.

4. Fugitive dust emissions during the construction period shall be minimized by covering or watering THE dust generation areas.

5. see next page
6. see next page

~~SPECIFIC CONDITIONS:~~

Emission Limits

1. The maximum allowable emissions from the DHCT3, when firing natural gas or low sulfur fuel oil, in accordance with the BACT determination, shall not exceed the following (Table I), at ISO conditions based upon the high heating values of the fuels (except during periods of start up, shutdown, malfunction, fuel switching, and load change). Barbara can you insert Table I after this condition

2. Visible emissions for full load operation shall not exceed 10% opacity when firing natural gas and 20% opacity when firing distillate fuel oil.

see back.

3. The following DHCT3 emission controls are tabulated for PSD purposes:

ESTIMATED EMISSIONS

POLLUTANT	METHOD OF CONTROL	Basis (a)
Sulfuric Acid Mist	Natural Gas/No. 2 Fuel Oil (b)	BACT
Inorganic Arsenic	Natural Gas/No. 2 Fuel Oil (b)	(c)
Beryllium	Natural Gas/No. 2 Fuel Oil (b)	(c)
Mercury	Natural Gas/No. 2 Fuel Oil (b)	(c)
Pb	Natural Gas/No. 2 Fuel Oil (b)	(c)

a. Since these pollutants are inherent constituents in the fuel, the basis for control will be by specifying that only natural gas and No. 2 fuel oil can be fired at the facility.

b. Only natural gas or No. 2 fuel oil will be combusted. The No. 2 fuel oil shall have a maximum sulfur content of 0.05% by weight except that the permittee is authorized for up to an equivalent of 55 hours of full load operation at ISO conditions using a fuel oil with 0.25% sulfur content.

c. Below PSD significant emissions level.

~~4. The permittee will install a dry low NOx combustor on DHCT3 for NOx control when firing natural gas. Control of NOx when firing fuel oil will be accomplished by water injection.~~

TABLE I
ALLOWABLE EMISSION LIMITS

POLLUTANT	FUEL	BASIS(a)	LB/HR(b)		TPY(c)	TPY(i)	TPY(j)
NO_x	GAS	15 ppmvd(d)	53		50.4	103.4	92.8
	Oil	48 ppmvd(e)(d)	190	Total	190		38
					240.4		130.8
VOC (f)	Gas	2 ppmvw	3		2.9	5.9	5.3
	Oil	5 ppmvw	6		6.0		1.2
				Total	8.9		6.5
CO	Gas	15 ppmvd	32		30.4	62.4	56
	Oil	30 ppmvd	65		65.0		13
			89		95.4		69
PM/PM_{10} (f)	Gas		7		6.7	13.7	12.3
	Oil(g)		15		15.0		3
				Total	21.7		15.3
SO_2	Gas		26		24.7	50.7	46
	Oil (0.05%) (h)		48		48		9.6
	Oil (0.25%) (h)		240		6.0		6.6
				Total	72.7		62.2
H_2SO_4	Gas		2.3		2.2	4.5	4.1
	Oil (0.05%) (h)		5.0		5.0		1.0
	Oil (0.25%) (h)		25		0.7		0.7
				Total	7.9		5.8

Could you make this little smaller

a. The values are the computational basis for the lb/hr numbers, which are the allowable emission limitations.

b. Emission limitations in lb/hr are blocked 24-hour averages (midnight to midnight), except for opacity which is based on 6-minute averages. All values, except opacity, are at ISO conditions.

c. Annual emission limits (TPY) are based on the DHCT3 operating at full load for a total of 3900 hours per year, with up to 2000 hours of oil-fired operation with the remaining 1900 hours on natural gas firing.

d. 15 ppmvd/48 ppmvd at 15% O_2, ISO corrected as specified in 40 CFR Subpart GG.

e. Fuel oil NO_x emissions are based on full load operation at ISO conditions and 15 percent oxygen. For fuel oil firing, NO_x levels of 48 ppmvd are based on a fuel bound nitrogen content of 0.030 percent by weight.

The emission limit for NO_X is adjusted as follows for higher fuel-bound nitrogen contents up to a maximum of 0.030 percent by weight:

FUEL-BOUND NITROGEN (% by weight)	**NO_X EMISSION LEVELS (ppmvd @ 15% O_2)**
0.015 or less	42
0.020	44
0.025	46
0.030	48

using the formula STD = 0.042 + F where:

STD = allowable NO_X emissions (% by volume at 15% O_2 and on a dry basis).

F = NO_X emission allowance for FBN defined by the following table:

FUEL BOUND NITROGEN (% by weight)	**F (NOx % by volume)**
$0 < N < 0.015$	0
$015 < N < 0.03$	0.04 (N-0.015)

Be consistent

The Permittee shall submit fuel bound nitrogen content data for the low sulfur fuel oil prior to commercial operation to the Bureau of Air Regulation in Tallahassee, and on each occasion that fuel oil is transferred to the storage tanks from any other source to the DEP Northeast District office ~~in Jacksonville~~. The percent FBN (Z) following each delivery of fuel shall be determined by the following operation:

$$x(Y) + m(n) = (x+m)\ (Z)$$

where x	= amount fuel in storage tank
y	= % FBN in storage tank
m	= amount fuel added
n	= % FBN of fuel added
Z	= % FBN of composite

f. Exclusive of background concentrations.

g. PM/PM_{10} emission limitations are exclusive of sulfuric acid mist and sulfates.

h. SO_2 emissions based on a maximum of 0.05 percent sulfur in the fuel oil except that up to an equivalent of 55 hours of full load operation at ISO conditions are authorized using fuel oil with a 0.25% sulfur content by weight. A 95.1% conversion of sulfur is assumed.

smaller letters of formula

small letters

i. Annual emission limits (TPY) based on 3900 hours on natural gas.

j. Annual emission limits (TPY) based on 3500 hours on natural gas and 400 hours on fuel oil No. 2 (0.05% S content).

why duplicate A 1.

Operating Rates

duplicate

3. The maximum heat input rates to DHCT3 at ISO conditions (i.e., 59° F, 60% relative humidity and sea level pressure) shall neither exceed 971.1 MMBtu/hr while firing natural gas, nor 990.6 MMBtu/hr while firing fuel oil. Heat input will vary depending on ambient conditions and the DHCT3 characteristics. Manufacturer's curves or equations for correction to other ambient conditions shall be provided to DEP Northeast District office at least 90 days before initial compliance testing.

A2.

4. On an annual basis, the DHCT3 may operate under the following scenarios:

a) 3900 hours on natural gas
b) 3500 hours on natural gas and 400 hours on No. 2 fuel oil (0.05% sulfur)
c) 1900 hours on natural gas, 2000 hours on No. 2 fuel oil (0.05% sulfur)

Dup'n A3.

5. Only natural gas (NG) or low sulfur fuel oil shall be fired in the combustion turbine. The maximum sulfur content of the fuel oil shall not exceed 0.05 percent, by weight except that the permittee shall be allowed up to an equivalent of 55 hours during full load operation (one time only) at ISO conditions using fuel oil with a sulfur content of 0.25 percent by weight. Thereafter, the maximum sulfur content shall not exceed 0.05 percent by weight.

5. ~~6~~. Any change in the method of operation, equipment or operating hours pursuant to Rule 17-212.200, F.A.C., Definitions-Modifications, shall be submitted to DER's Bureau of Air Regulation and Northeast District offices.

6. ~~7~~. Any other operating parameters established during compliance testing and/or inspection that will ensure the proper operation of this facility shall be included in the operating permit.

Compliance Determination hold.

8. Compliance with the allowable emission limiting standards shall be determined ~~(while operating at 95-100% of the permitted maximum heat rate input corresponding to the particular ambient conditions)~~ within 60 days after achieving the maximum production rate at which this unit will be operated, but not later than 180 days of initial operation of the maximum capability of the unit and annually thereafter, by the following reference methods as described in 40 CFR 60, Appendix A (July, 1992 version) and adopted by reference in F.A.C. Rule 17-297.

Isn't Combustion Turbine rule final?

Check. SC #120-K

Initial (I) compliance tests shall be performed on the DHCT3 using both fuels. Annual (A) compliance tests shall be performed on the DHCT3 with the fuel(s) used for more than 400 hours in the precceding 12-month period.

- Method 1	Sample and Velocity Traverses for Stationary Sources
- Method 2	Determination of Stack Gas Velocity and Volumetric Flow Rate
- Method 3	Gas Analysis
- Method 5, 5B, 5F or	Determination of Particulate Emissions from Stationary Sources (I, A, for oil only)
Method 17	~~Determination of Particulate Emissions from Stationary Sources (I, A, for oil only)~~ redundant
- Method 18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography
- Method 9	Visual Determination of the Opacity of Emissions from Stationary Sources
- Method 8	Determination of Sulfuric Acid Mist and Sulfur Dioxide Emissions from Stationary Sources
- Method 10	Determination of Carbon Monoxide Emission from Stationary Sources
- Method 20	Determination of Nitrogen Oxides, Sulfur Dioxide, and Diluent Emissions from Stationary Gas Turbines
- Method 18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography.
or	
- Method 25A	Determination of Total Gaseous Organic Concentrations Using a Flame Ionization Analyzer

Other DEP approved methods may be used for compliance testing after prior Departmental approval.

2. ~~9~~. Compliance with the SO_2 and sulfuric acid mist emission limit can also be determined by calculations based on fuel analysis using ASTM D4294 (or equivalent) for the sulfur content of liquid fuels and D1072-80, D3031-81, D4084-82 or ASTM D3246-81 (or equivalent) for sulfur content of gaseous fuel (I and A if deemed necessary by DEP). Alternatively, natural gas supplier data for sulfur content may be submitted

3. ~~10~~. During performance tests, to determine compliance with the NO_x standard, measured NO_x emissions at 15 percent oxygen will be adjusted to ISO ambient atmospheric conditions by the following correction factor:

$$NO_x = (NO_{x\ obs}) \left(\frac{P_{ref}}{P_{obs}}\right)^{0.5} e^{19\,(H_{obs} - 0.00633)} \left(\frac{288°K}{T_{AMB}}\right)^{1.53}$$

where:

NO_x = Emissions of NO_x at 15 percent oxygen and ISO standard ambient conditions.

$NO_{x\ obs}$ = Measured NO_x emission at 15 percent oxygen, ppmv.

P_{ref} = Reference combustor inlet absolute pressure at 101.3 kilopascals (1 atmosphere) ambient pressure.

P_{obs} = Measured combustor inlet absolute pressure at test ambient pressure.

H_{obs} = Specific humidity of ambient air at test.

e = Transcendental constant (2.718).

T_{AMB} = Temperature of ambient air at test.

4 ~~11.~~ The permittee will install a dry low NO_x combustor on DHCT3 for NO_x control when firing natural gas. Control of NO_x when firing fuel oil will be accomplished by water injection. The water to fuel ratio at which annual compliance is achieved shall be incorporated into the permit and shall be continuously monitored. The system shall meet the requirements of 40 CFR Part 60, Subpart GG.

5 ~~12.~~ Test results will be the average of three valid one-hour runs. The DEP Northeast District office will be notified at least 30 days in writing in advance of the compliance test(s). This combustion turbine shall operate between 95% and 100% of maximum capacity for the ambient conditions experienced during compliance test(s). The turbine manufacturer's capacity vs temperature (ambient) curve shall be included with the compliance test results. Compliance test results shall be submitted to the DEP Northeast District office no later than 45 days after completion.

6 ~~13.~~ Sulfur and nitrogen content and lower heating value of the fuel being fired in the combustion turbines shall be determined as specified in 40 CFR 60.334(b). Any request for a future custom monitoring schedule shall be made in writing and directed to the DEP Northeast District office. Any custom schedule approved by DEP pursuant to 40 CFR 60.334(b) will be recognized as enforceable provisions of the permit, provided that the holder of this permit demonstrates that the provisions of the schedule will be adequate to assure continuous compliance. The daily records of natural gas and distillate fuel oil usage shall be kept by the company for a two-year period for regulatory agency inspection purposes. For sulfur dioxide, periods of excess emissions shall be reported if the fuel being fired in the gas turbine exceeds 0.05 percent sulfur by weight except for up to an equivalent of 55 hours of full load operation using 0.25% sulfur oil.

7 ~~14.~~ Excess emissions from this turbine resulting from startup, shutdown, malfunction, or load change shall be acceptable providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for a longer duration. Best operating

Come on! use DEP or Department! Try to be consistent

DEP Northeast District office

practices shall be documented in writing and a copy submitted to the Department along with the initial compliance test data. The document may be updated as needed with all updates submitted to the department within thirty (30) days of implementation and shall include time limitations on excess emissions caused by turbine startup.

Notification, Reporting and Recordkeeping Bold

1 ~~15. The following protocols shall be submitted to the Department's Air Program, within the~~ DEP Northeast District office for approval;

a. CEMS - The Federal Acid Rain Program requirements of 40 CFR 75 shall apply when those requirements become effective within the state.

b. Performance Test Protocol - At least 90 days prior to conducting the initial performance tests required by this permit. The permittee shall submit to the Department's Air Program, within the Northeast District office, a protocol outlining the procedures to be followed, the test methods and any differences between the reference methods and the test methods proposed to be used to verify compliance with the conditions of this permit. The Department shall approve the testing protocol provided that it meets the requirements of this permit.

c. All measurements, records, and other data required to be maintained by GRU shall be retained for at least five (5) years following the date on which such measurements, records, or data are recorded. These data shall be made available ~~to the Department~~ to the DEP upon request. The DEP Northeast District office shall be notified in writing at least 15 days prior to the testing of any instrument required to be operated by these conditions of certification in order to allow witnessing by authorized personnel.

parentheses

Monitoring Requirements Bold

1 ~~16.~~ The permittee shall install, calibrate, maintain, and operate a continuous emission monitor in the stack to measure and record the nitrogen oxides emissions from this source. The continuous emission monitor must comply with F.A.C. Rule 17-297.500, 40 CFR Appendix F Quality Assurance Procedures, 40 CFR 60, Appendix B, Performance Specification 2 (July 1, 1993) and 40 CFR 75. Period of startup, shutdown, fuel switching, malfunction, and load change shall be recorded.

Did you define? How is C different than DHCT? ?

2 ~~17.~~ A continuous monitoring system shall be installed to monitor and record the fuel consumption on the CT. While water/steam injection is being utilized for NO_X control, the water/steam to fuel ratio at which compliance is achieved shall be incorporated into the permit and shall be continuously monitored. The system shall meet the requirements of 40 CFR Part 60, Subpart GG.

combustion turbine

3 ~~18~~. A malfunction means any sudden and unavoidable failure of air pollution control equiopment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

Rule Requirements moved

1 ~~19~~. This source shall comply with all applicable provisions of Chapter 403, Florida Statutes, Chapters 17-210, 212, 275, 296, 297 and 17-4, Florida Administrative Code and 40 CFR 60 (July, 1992 version).

2 ~~20~~. The sources shall comply with all requirements of 40 CFR 60, Subpart GG and Subpart A, and F.A.C. Rule 17-296.800,(2)(a), Standards of Performance for Stationary Gas Turbines. All notifications and reports required by this specific condition shall be submitted to the Department's Air Program within the Northeast District office.

3 ~~21~~. Issuance of this permit does not relieve the facility owner or operator from compliance with any applicable federal, state, or local permitting requirements and regulations (F.A.C. Rule 17-210.300(1)).

4 ~~22~~. This source shall be in compliance with all applicable provisions of F.A.C. Rules 17-210.650: Circumvention; 17-210.700: Excess Emissions; 17-296.800: Standards of Performance for New Stationary Sources (NSPS); 17-297: Stationary Sources-Emissions Monitoring; and, 17-4.130: Plant Operation-Problems.

5 ~~23~~. If construction does not commence within 18 months of issuance of this permit, then the permittee shall obtain from the ~~Department~~ DEP Bureau of Air Regulation a review and, if necessary, a modification of the control technology and allowable emissions for the unit(s) on which contruction has not commenced (40 CFR 52.21(r)(2)).

6 ~~24~~. Quarterly excess emission reports, in accordance with the July 1, 1993 version of 40 CFR 60.7 and 60.334 shall be submitted to the ~~Department's~~ DEP Northeast District office.

~~25. Fugitive dust emissions, during the construction period, shall be minimized by covering or watering dust generation areas.~~

7 ~~26~~. Pursuant to F.A.C. Rule 17-210.300(2), Air Operating Permits, the permittee is required to submit annual reports on the actual operating rates and emissions from this facility. These reports shall include, but are not limited to the following: sulfur

content and the lower heating value of the fuel being fired, fuel usage, hours of operation, air emissions limits, etc. Annual reports shall be sent to the Department's Northeast District office by March 1 of each calendar year.

DEP

8 ~~27~~. The permittee, for good cause, may request that this construction permit be extended. Such a request shall be submitted to the Bureau of Air Regulation prior to 60 days before the expiration of the permit (F.A.C. Rule 17-4.090).

9 ~~28~~. An application for an operation permit must be submitted to the Northeast District office at least 90 days prior to the expiration date of this construction permit. To properly apply for an operation permit, the applicant shall submit the appropriate application form, fee, certification that construction was completed noting any deviations from the conditions in the construction permit, and compliance test reports as required by this permit (F.A.C. Rules 17-4.055 and 17-4.220).

Modifications Bold

The permittee shall give written notification to the DEP ~~Department~~ ~~Northeast District office~~ Bureau of Air Regulation when there is any modification to this facility. This notice shall be submitted sufficiently in advance of any critical date involved to allow sufficient time for review, discussion, and revision of plans, if necessary. Such notice shall include, but not be limited to, information describing the precise nature of the change; modifications to any emission control system; production capacity of the facility before and after the change; and the anticipated completion date of the change.

Issued this ______ day
of ______________, 1994

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL ~~REGULATION~~ Protection

Virginia B. Wetherell
Secretary

Best Available Control Technology (BACT) Determination
Gainesville Regional Authority
Alachua County
PSD-FL-212

Gainesville Regional Utilities proposes to construct a 74 MW simple cycle combustion turbine at the existing Deerhaven site approximately seven miles north of Gainesville in Alachua County. This unit will be a 74 MW General Electric (GE) simple cycle turbine generator (CT). The selected CT, designated as DHCT3, is a GE Model MS 7001 EA with dry low NO_x combustors.

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The applicant has requested to burn natural gas for 1510 hours per year, 390 hours per year in the power augmentation ~~mode (PA)~~ and distillate fuel oil, with a 0.05 percent sulfur content for a maximum of 2000 hours per year. The applicant has indicated the maximum annual tonnage of regulated air pollutants emitted from the facility at 100 percent, 59° F and type of fuel fired to be as follows:

Pollutant	Emissions (TPY) Gas	Gas w/PA	Oil	Total	PSD Significant Emission Rate (TPY)
	1510 Hrs	390 Hrs	2000 Hrs		
NO_x	40	23	192	242	40
SO_2	13	6	48	67	40
PM/PM_{10}	4	1	15	20	25/15
CO	16	8	65	89	100
VOC	2	1	6	9	40
H_2SO_4	1.2	1	5	7.2	0.0004
Be			0.0004	0.0004	0.1
Hg			0.001	0.001	0.6
Pb			0.0638	0.0638	0
As			0	0	0

Florida Administrative Code (F.A.C.) Rule 17-212.400(2) (f) (3) requires a BACT review for all regulated pollutants emitted in an amount equal to or greater than the significant emission rates listed in the previous table.

<u>Date of Receipt of a BACT Application</u>

March 25, 1994

BACT Determination Requested by the Applicant

Pollutant	Proposed Limits
NO_x	15 ppmvd @ 15% O_2 (natural gas burning) 54 ppmvd @ 15% O_2 (for oil firing) 30 ppmvd @ 15% O_2 (natural gas firing power augmentation mode) Control Technology. Dry Low-NO_x combustor when firing natural gas and steam/water injection when firing distillate oil and during power augmentation mode
SO_2	0.05% sulfur by weight (fuel oil firing)

BACT Determination Procedure

In accordance with Florida Administrative Code Chapter 17-212, this BACT determination is based on the maximum degree of reduction of each pollutant emitted which the 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:

(a) Any Environmental Protection Agency determination of Best Available Control Technology 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).

(b) All scientific, engineering, and technical material and other information available to the Department.

(c) The emission limiting standards or BACT determination of any other state.

(d) 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 source in question the most stringent control available for a similar or identical source or source category. If it is shown that this level of control is technically or economically infeasible for the source 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 air pollutant emissions from combined cycle power plants can be grouped into categories based upon what control equipment and techniques are available to control emissions from these facilities. Using this approach, the emissions can be classified as follows:

- o Combustion Products (e.g., particulates). Controlled generally by good combustion of clean fuels.
- o Products of Incomplete Combustion (e.g., CO). Control is largely achieved by proper combustion techniques.
- o Acid Gases (e.g., NO_x). Controlled generally by gaseous control devices.

Grouping the pollutants in this manner facilitates the BACT analysis because it enables the equipment available to control the type or group of pollutants emitted and the corresponding energy, economic, and environmental impacts to be examined on a common basis. Although all of the pollutants addressed in the BACT analysis may be subject to a specific emission limited standards as a result of PSD review, the control of "nonregulated" air pollutants is considered in imposing a more stringent BACT limit on a "regulated" pollutant (i.e., particulates, sulfur dioxide, fluorides, sulfuric acid mist, etc,), if a reduction in "nonregulated" air pollutants can be directly attributed to the control device selected as BACT for the abatement of the "regulated" pollutants.

<u>ACID GASES</u>

Nitrogen Oxides (NOx)

The emissions of nitrogen oxides represent a significant proportion of the total emissions generated by this project, and need to be controlled if deemed appropriate. As such, the applicant presented an extensive analysis of the different available technologies for NO_x control.

The applicant has stated that BACT for nitrogen oxides will be met by using dry low NO_x combustor design and water injection to limit emissions to 15 ppmvd (corrected to 15% O_2) when burning natural gas and 54 ppmvd (corrected to 15% O_2) when burning fuel oil.

A review of the EPA's BACT/LAER Clearinghouse indicates that the lowest NO_x emission limit established to date for a combustion turbine is 4.5 ppmvd at 15% oxygen. This level of control was accomplished through the use of water injection and a selective catalytic reduction (SCR) system.

Selective catalytic reduction is a post-combustion method for control of NO_x emissions. The SCR process combines vaporized ammonia with NO_x in the presence of a catalyst to form nitrogen and water. The vaporized ammonia is injected into the exhaust gases prior to passage through the catalyst bed. The SCR process can achieve up to 90% reduction of NO_x with a new catalyst. As the catalyst ages, the maximum NO_x reduction will decrease to approximately 86 percent.

The effect of exhaust gas temperature on NOx reduction depends on the specific catalyst formulation and reactor design. Generally, SCR units can be designed to achieve effective NOx control over a 100-300°F operating window within the bounds of 450-800°F, although recently developed zeolite-based catalysts are claimed to be capable of operating at temperatures as high as 950°.

Most commercial SCR systems operate over a temperature range of about 600-750°F. At levels above and below this window, the specific catalyst formulation will not be effective and NO_x reduction will decrease. Operating at high temperatures can permanently damage the catalyst through sintering of surfaces.

Increased water vapor content in the exhaust gas (as would result from water or steam injection in the gas turbine combustor) can shift the operating temperature window of the SCR reactor to slightly higher levels.

The exhaust temperatures of the proposed simple cycle CTs for this site will range from 995°F to 1,100°F. At temperatures of 1,100°F and above, the zeolite catalyst (reported to operate normally within 1,050°F) will be irreparably damaged.

Based on the GE data sheets for the proposed DHCT3, provided by the applicant, exhaust temperatures will range from 995°F to 1,100°F, depending upon the fuel fired, ambient temperature and load. Since the zeolite catalysts were reported to operate in this temperature range, ENSERCH Environmental investigated the technical feasibility of using such a system. Because the zeolite catalysts are new, only one vendor (Norton Chemical Process Products Corporation, P.O. Box 350, Akron, Ohio 44309-0350) was capable of providing a cost estimate. A second vendor was contacted and a cost estimate requested but no response was received. This cost estimate noted that their current zeolite catalyst is limited to a maximum upper temperature of 1,050°F and that without an air injection system to cool the exhaust gases at the zeolite catalyst, its use would be infeasible. Review of the GE data sheets for the Deerhaven CT confirmed the vendor's exhaust gas temperature findings. However, since the maximum temperature limit of the zeolite catalyst would be reached only occasionally (i.e., loads < 100%), ENSERCH Environmental requested the vendor to revise the initial cost estimate and include the cost of an air injection system.

Based on the information obtained from the vendor, the use of a SCR system equipped with a zeolite catalyst and an air injection system was deemed to be only <u>potentially</u> technically feasible based upon its limited usage on simple cycle CTs. In addition, although the concept of an air injection system is easily visualized, its use commercially has been documented only once in the clearinghouses as a commercially available response to the temperature limitations of SCR. Although only potentially technically feasible, ENSERCH Environmental evaluated the impacts of an SCR system equipped with a high temperature zeolite catalyst and an air injection system as the available post-combustion control technology needed to meet the most stringent emission limitations.

For the simple cycle combustion turbine, based on the information supplied by the applicant it is estimated that the maximum annual NO_x emissions using a low NO_x combustor will be 276.42 tons/year. Assuming that SCR would reduce the NOx emissions by approximatley 80%, about 58.22 tons of NO_x would be emitted annually. When this reduction is taken into consideration with the total levelized annual operating cost of $1,455,957.33; the incremented cost effectiveness ($/ton) of controlling NO_x is $6,672.58 for this project. These calculated costs are higher than has previously been approved as BACT.

A review of ~~the~~ A latest DEP BACT determination~~s~~ show limits of 15 and 9 ppmv~~d~~ (natural gas) using low-NO_x ~~burn~~ combustor technology for combined cycle turbines. General Electric is currently developing programs using both steam/water injection and dry low NO_x combustors to achieve NO_x emission control level of 9 ppm when firing natural gas. Therefore, since this technology will be available by 1998, the Department has accepted water injection, dry low NO_x combustor design, and the 15 ppmvd (natural gas)/42 ppmvd (oil) at 15% O_2 as BACT (a maximum allowance of 6 ppmvd for fuel bound nitrogen is permitted). After 1/1/98, the NO_x basis of 15 ppmvd @ 15% O_2 (natural gas firing) must be met after the ISO adjustments specified in 40 CFR 60, Subpart GG, is applied.

Sulfur Dioxide (SO_2) and Sulfuric Acid Mist (H_2SO_4)

The applicant has stated that the sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) emissions when firing fuel oil will be controlled by using fuel oil with a maximum sulfur content of 0.05% by weight. This will result in an annual emission rate of 67 tons SO_2 per year on gas and 7.2 tons H_2SO_4 mist per year (operating at 1900 hours per year on natural gas and 2000 hours per year on No. 2 fuel oil (0.05%S).

In accordance with the "top down" BACT review approach, only two alternatives exist that would result in more stringent SO_2 emissions. These include the use of a lower sulfur content fuel oil or the use of wet lime or limestone-based scrubbers, otherwise known as flue gas desulfurization (FGD).

In developing the NSPS for stationary gas turbines, EPA recognized that FGD technology was inappropriate to apply to these combustion units. EPA acknowledged in the preamble of the proposed NSPS that "Due to the high volumes of exhaust gases, the cost of flue gas desulfurization (FGD) to control SO_2 emission from stationary gas turbines is considered unreasonable."(23). EPA reinforced this point when, later on in the preamble, they stated that "FGD...would cost about two to three times as much as the gas turbine."(23). The economic impact of applying FGD today would be no different.

Furthermore, the application of FGD would have negative environmental and energy impacts. Sludge would be generated that would have to be disposed of properly, and there would be increased utility (electricity and water) costs associated with the operation of a FGD system. Finally, there is no information in the open literature to indicate that FGD has ever been applied to stationary gas turbines burning distillate oil.

The elimination of flue gas control as a BACT option then leaves the use of low sulfur fuel oil as the next option to be investigated. Gainesville Utilities, as stated above, has proposed the use of No. 2 fuel oil with a 0.05% sulfur by weight as BACT for this project. ~~The Department accepts their proposal as BACT for this project.~~

BACT Determination by DEP

NO_x Control

The information that the applicant presented and Department calculations indicates that the cost per ton of controlling NO_x for this turbine [$6,618 per ton] is high compared to other BACT determinations which require SCR. Based on the information presented by the applicant, the Department believes that the use of SCR for NO_x control is not justifiable as BACT at this time.

It is the Department's understanding that General Electric is developing programs either steam/water injection or dry low NO_x combustor technology to achieve a NO_x emission control level of 9 ppm when firing natural gas. Several prior CT projects have already been permitted at 15 ppmvd firing natural gas and 42 ppmvd when firing No. 2 fuel oil. This determination is consistent with earlier determinations. Therefore, the Department has determined that the allowable BACT limit for this project will be 15 ppmvd corrected to a dry basis and 15% O_2, corrected to ISO conditions as specified in 40 CFR 60, Subpart GG no later than 1/1/98.

SO2 Control

The Department accepts the applicants' proposal AS

BACT for sulfur dioxide ~~is~~ the burning of fuel oil No. 2 with 0.05% sulfur by weight.

Bact Emission Limits

The emission limits for the Gainesville Utilities project are ~~thereby~~ established as follows:

OK

EMISSIONS LIMITATIONS

POLLUTANT	FUEL	BASIS(a)	LB/HR(b)
NO_x	GAS	15 ppmvd(c)	53
	Oil	48 ppmvd(d)(c)	190
VOC (e)	Gas	2 ppmvw	3
	Oil	5 ppmvw	6
CO	Gas	15 ppmvd	32
	Oil	30 ppmvd	65
PM/PM_{10} (e)	Gas		7
	Oil(f)		15
SO_2	Gas		26
	Oil (0.05%) (g)		48
	Oil (0.25%) (h)		240
H_2SO_4	Gas		2.3
	Oil (0.05%) (g)		5.0
	Oil (0.25%) (h)		25

a. The values are the computational basis for the lb/hr numbers, which are the allowable emission limitations.

b. Emission limitations in lb/hr and blocked 24-hour averages (midnight to midnight), except for opacity which is based on 6-minutes averages. All values, except opacity, are at ISO conditions.

c. 15 ppmvd/48 ppmvd at 15% O_2, ISO corrected as specified in 40 CFR 60, Subpart GG.

d. Fuel oil NO_x emissions are based on full load operation at ISO conditions and 15 percent oxygen. For fuel oil firing, NO_x levels of 42 ppmvd @ 15 percent O_2 are based on a fuel bound

what did you decide to do with lead?

nitrogen content of 0.015 percent or less. The emission limit for NO_X is adjusted as follows for higher fuel nitrogen contents up to a maximum of 0.030 percent by weight:

FUEL BOUND NITROGEN (% BY WEIGHT)	NO_X LEVELS (PPMVD @ 15% O2)	NO_X EMISSIONS LB/HR
0.015 or less	42	166
0.020	44	174
0.025	46	182
0.030	48	192

using the formula STD = 0.0042 + F where:

STD = allowable NO_X emissions (percent by volume at 15 percent O_2 and on a dry basis).

F = NO_X emission allowance for fuel-bound nitrogen defined by the following table:

FUEL-BOUND NITROGEN (% BY WEIGHT)	F (NOX % BY VOLUME)
0 < N > 0.015	0
0.015 < N < 0.03	0.04 (N-0/015)

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

GRU shall submit fuel bound nitrogen content data for the low sulfur fuel oil prior to commercial operation.

e. Exclusive of background concentrations.

f. PM/PM_{10} emission limitations are exclusive of sulfuric acid mist.

g. SO_2 emissions are based on a maximum of 0.05 percent sulfur in the fuel oil and sulfates.

h. SO_2 emissions based on a maximum of 0.05 percent sulfur in the fuel oil except that up to an equivalent of 55 hours of full load operation at ISO conditions are authorized using fuel oil with a 0.25% sulfur content by weight. A 95.1% conversion of sulfur is assumed.

The applicant requested to be allowed to emit higher NO_X while firing in a power augmentation mode. Power augmentation allows the firing of additional fuel to produce more megawatts during peak-demand periods. The Department does not have the authority to permit the violation of a BACT determination. In life threatening situations (severe cold, hurricane, etc.) sources have been granted an emergency order allowing a temporary violation of the air permit standards by the Department Secretary. This was done on a case by case basis.

<u>Details of the Analysis May be Obtained by Contacting</u>:

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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
______________________, 1994 Date	______________________, 1994 Date