STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
NOTICE OF PERMIT

In the matter of an
Application for Permit by:

DER File No. AC 01-204652
PSD-FL-181
Alachua County

Mr. R. W. Neiser
Florida Power Corporation
3201-34th Street South
St. Petersburg, Florida 33733
/

Enclosed is Permit Number AC 01-204652 to construct a 43 MW cogeneration facility at the University of Florida's Central Heat Plant facility in Gainesville, Alachua County, Florida, issued 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 30 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

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 August 17, 1992 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 8/17/92
(Clerk) (Date)

Copies furnished to:
A. Kutyna, NED
J. Harper, EPA
C. Shaver, NPS
K. Kosky, P.E.

P 062 921 988

Receipt for Certified Mail

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

Sent to: Mr. R. W. Neiser, FPC	
Street and No.: 3201-34th Street South	
P.O., State and ZIP Code: St. Petersburg, FL 33733	
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: 8-17-92 Permit: AC 01-204652	

PS Form 3800, June 1991

Final

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 Fee will provide you the signature of the person delivered to and the date of delivery.

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. R. W. Neiser
Florida Power Corporation
3201-34th Street South
St. Petersburg, FL 33733

4a. Article Number
P 062 921 988

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

7. Date of Delivery
AUG 20 1992

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form 3811, November 1990 ☆U.S. GPO: 1991—287-066 **DOMESTIC RETURN RECEIPT**

Final Determination

Florida Power Corporation/University
of Florida Cogeneration Project
Alachua County, Florida

Permit No. AC 01-204652
PSD-FL-181

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

August 7, 1992

Final Determination

The Technical Evaluation and Preliminary Determination for the permit to construct a 43 megawatt cogeneration facility at the University of Florida Central Heat Plant in Gainesville, Alachua County, Florida, was distributed on June 30, 1992. The Notice of Intent to Issue was published in the Gainesville Sun on July 3, 1992. Copies of the evaluation were available for public inspection at the Department's Tallahassee and Jacksonville offices.

Comments were submitted by the applicant on July 29, 1992, requesting modification of Specific Conditions Nos. 3, 4, and 7. The Department made the following changes in response to those comments:

<u>Specific Condition No. 3</u> - Specific limits for Boilers 4 and 5 were replaced with a total NO_x cap to provide operational flexibility in the event of gas curtailments.

<u>Specific Condition No. 4</u> - The required operating rate during the compliance test was modified to reflect the maximum capacity achievable at a given ambient temperature.

<u>Specific Condition No. 7</u> - Language was added to clarify that a revised BACT analysis is dependent on the facility meeting the emission limits.

The final action of the Department will be to issue construction permit AC 01-204652 (PSD-FL-181) as modified.

Florida Department of Environmental Regulation

Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

PERMITTEE:
Florida Power Corporation
3201 - 34th Street South
St. Petersburg, FL 33733

Permit Number: AC 01-204652
PSD-FL-181
Expiration Date: December 31, 1994
County: Alachua
Latitude/Longitude: 29°38'23"N
82°20'55"W
Project: UF Cogeneration Facility

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-2 and 17-4. 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 and made a part hereof and specifically described as follows:

For the construction of a 43 Megawatt cogeneration facility consisting of replacement of existing boiler Nos. 1, 2, and 3 with a GE LM-6000 combustion turbine in series with a duct burner at a designed flow of 325,200 ACFM, and operating existing boiler Nos. 4 and 5 as auxiliary units.

Particulate emissions shall be controlled by using clean fuels and good combustion practices. CO emissions shall be initially controlled by proper combustion techniques. NO_X emissions shall be initially controlled by steam injection. Future control requirements for CO and NOx will be established by a revised BACT determination if deemed necessary by the Department.

The facility is located at the existing Central Heat Plant on the campus of the University of Florida in Gainseville, Alachua County, Florida. The UTM coordinates are 369.4 km East and 3,279.3 km North.

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

<u>Attachments are listed below</u>:

1. FPC letter dated 11-13-91.
2. FPC letter dated 11-25-91.
3. KBN letter dated 12-2-91.
4. DER incompleteness letter dated 12-31-91.
5. FPC letter dated 1-2-92.
6. EPA letter dated 1-8-92.
7. DER letter to EPA dated 1-16-92.

Attachments Cont'd

8. KBN letter dated 1-30-92.
9. FPC letter to EPA dated 2-6-92.
10. DER letter to EPA dated 2-12-92.
11. DER letter to EPA dated 2-14-92.
12. FPC response to incompleteness dated 3-5-92.
13. FWS letter to DER dated 4-2-92.
14. EPA letter to DER dated 4-8-92.
15. KBN letter to DER dated 4-8-92.
16. EPA letter to DER dated 6-16-92.
17. FPC letter to DER dated 6-19-92.
18. FPC letter to DER dated 7-29-92.

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, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

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), Florida Statutes, 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.

GENERAL CONDITIONS:

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

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 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

GENERAL CONDITIONS:

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 Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. 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 Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-30.300, F.A.C., as applicable. 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)

GENERAL CONDITIONS:

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 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:

1. Unless otherwise indicated, the construction and operation of the subject cogeneration facility shall be in accordance with the capacities and specifications stated in the application.

SPECIFIC CONDITIONS:

2. Emissions from this facility shall not exceed the limits listed below:

Pollutant	Source	Fuel	Basis of Limit	lbs/hr	tons/yr
NOx	Turbine	Gas	EBM*:25 ppmvd @ 15% O2	35.0	142.7
	Turbine	Oil	EBM*:42 ppmvd @ 15% O2	66.3	7.3
	D.Burner	Gas	EBM*:0.1 lb/MMBTU	18.7	24.6
					179.6
SO2	Turbine	Oil	BACT:0.5% Sulfur Max.	-	-
	Boiler 4	Oil	BACT:0.5% Sulfur Max.	-	-
	Boiler 5	Oil	BACT:0.5% Sulfur Max.	-	-
VE	Turbine	Gas/Oil	Equivalent of mass EBM*	10%/20% opacity**	
	D.Burner	Gas	" " "	10% opacity	
	Boiler 4	Gas/Oil	" " "	10%/20% opacity**	
	Boiler 5	Gas/Oil	" " "	10%/20% opacity**	
CO	Turbine	Gas	BACT:42 ppmvd	38.8	158.0
	Turbine	Oil	EBA***:75 ppmvd	70.5	7.7
	D.Burner	Gas	BACT:0.15 lb/MMBTU****	28.1	36.9

*EBM: Established by manufacturer
**Except for one 6-minute period per hour of not more than 27% opacity
***EBA: Established by applicant
****BACT limit proposed by applicant in Table A-2 of application

3. Fuel consumption rates and hours of operation for the turbine and duct burner shall not exceed those listed below:

	Natural Gas			No. 2 Fuel Oil		
	M ft3/hr*	MM ft3/yr	hrs/yr*	M gal/hr*	M gal/yr	hrs/yr*
Turbine	367.9	2997.2**	8146.8**	2.9	635.1	219.0**
Duct Burner	197.7	519.5	2628.0	0	0	0

*Based on maximum firing rates. Units may run at lower rates for more hours within annual fuel limits.

**An additional 1.9 hours/yr operation on natural gas will be allowed for each 1.0 hour/yr that fuel oil is not burned (up to 219 x 1.9 hours/yr), in which case, the emission limits in Specific Condition No. 2 shall be adjusted accordingly.

$$367.9 \times 10^3 \ \frac{ft^3}{hr} \times 1{,}100 \frac{Btu}{ft^3} = 404.7 \ MMBtu/hr$$

SPECIFIC CONDITIONS:

Boilers Nos. 4 and 5, firing natural gas or No. 2 fuel oil, may be operated as necessary for backup, as long as total NO_x emissions from the four sources within the permitted facility do not exceed 194.3 tons NO_x per year. The permittee shall maintain the required fuel use records to demonstrate compliance with this condition and include the total NO_x emission calculation in each annual operating report.

19.7 TPY From 2 boilers

4. Before this construction permit expires, the cogeneration facility and Central Heat Plant (Boilers 4 and 5) stacks shall be sampled or tested as applicable according to the emission limits in Specific Condition No. 2. Annual compliance tests shall be conducted each year thereafter. Compliance tests shall be run at 96% to 100% of the maximum capacity achievable for the average ambient temperature during the compliance tests. The turbine manufacturer's capacity vs. temperature (ambient) curve shall be included with the compliance test results. Tests shall be conducted using the following reference methods:

NO_x: EPA Method 20
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9
CO: EPA Method 10

5. The DER Northeast District office shall be notified at least 30 days prior to the compliance tests. Compliance test results shall be submitted to the DER Northeast District office and the Bureau of Air Regulation office within 45 days after completion of the tests. Sampling facilities, methods, and reporting shall be in accordance with F.A.C. Rule 17-2.700 and 40 CFR 60, Appendix A.

6. A continuous operations monitoring system shall be installed, operated, and maintained in accordance with 40 CFR 60.334. The natural gas, fuel oil and steam injection flows to the cogeneration turbine along with the power output of the generator shall be metered and continuously recorded. The data shall be logged daily and maintained so that it can be provided to DER upon request.

7. The permittee shall have the option of including, in the initial construction, adequate modules and other provisions necessary for future installation of state-of-the-art catalytic abatement or equivalent CO and NOx control systems. Within 90 days of receipt of the initial compliance test results, the Department shall, if CO emission limits are not met, review the need for making a revised determination of Best Available Control Technology for CO.

PERMITTEE:
Florida Power Corporation

Permit Number: AC 01-204652
PSD-FL-181
Expiration Date: December 31, 1994

SPECIFIC CONDITIONS:

If test results from the turbine and duct burner show that it is unlikely that NO_X limits can be met, a revised BACT determination for NO_X shall also be considered. The Department may revise the BACT determination to require installation of such technology if so indicated by the revised BACT cost/benefit analysis. If the permittee has elected not to provide for future addition of such technology in the initial construction and later applies for a permit modification to increase capacity, the retrofit costs associated with not making provisions for such technology (initially) shall not be considered by the Department in the retrofit cost analysis required for the future expansion.

8. Boilers Nos. 1, 2 and 3 shall permanently cease operation upon receipt of the operation permit for the cogeneration facility.

9. 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).

10. 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).

Issued this 17th day
of August, 1992

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

Carol M. Browner

Carol M. Browner, Secretary

State of Florida
DEPARTMENT OF ENVIRONMENTAL REGULATION

For Routing To Other Than The Addressee	
To:	Location:
To:	Location:
To:	Location:
From:	Date:

Interoffice Memorandum

TO: Carol M. Browner

for FROM: Howard L. Rhodes

DATE: August 14, 1992

SUBJ: Approval of Construction Permit AC 01-204652 (PSD-FL-181)
Florida Power Corporation

Attached for your approval and signature is a permit prepared by the Bureau of Air Regulation for the above mentioned company to construct a 43 megawatt cogeneration facility at the University of Florida in Gainesville.

For years, Florida Power Corporation has supplied power for the University of Florida's Gainesville campus. The University's steam requirements have been provided by five boilers operated by the University. This cogeneration project represents a joint effort by the University and the electric utility to provide both power and steam requirements for the Gainesville campus while reducing energy consumption substantially. Florida Power will own and operate the new cogeneration facility on property leased from the University. Three of the five existing boilers will be shut down permanently while the other two remain for backup. Fuel for the new turbine generator will be natural gas with distillate fuel oil being used during periods of gas curtailment.

This project is not controversial and represents a reduction in allowable emissions as a result of taking the old inefficient boilers out of service.

HLR/JR/plm

Attachments

Revised
Best Available Control Technology (BACT) Determination
University of Florida Cogeneration Project
Alachua County

The applicant proposes to install a 43 MW cogeneration facility to replace existing boiler capacity at the University of Florida - Gainesville campus in Alachua County. The facility will consist of a General Electric LM-6000 Gas Turbine Generator exhausting through a duct-fired heat recovery steam generator which will produce steam for the University campus. The turbine and duct burner will be fired by natural gas with No. 2 fuel oil being used only as a backup fuel for the turbine.

No steam turbine?

A BACT determination is required for all regulated air pollutants emitted in amounts equal to or greater than the significant emission rates listed in Table 500-2 of Florida Administrative Code (F.A.C.) Rule 17-2.500.

The following table presents the estimated actual emissions in tons per year proposed by the applicant for NO_x, SO_2, PM/PM_{10}, VOC, and H_2SO_4. The Department accepts the applicant's proposed emissions for those pollutants, but will require a more stringent CO limit for the turbine during natural gas firing than proposed by the applicant (42 ppmvd vs. 75 ppmvd).

	Gas Turbine		Duct Burner	Total	Offsets	Increase	PSD
	NG	Oil	NG				
NO_x	142.7	7.3	24.6	174.6	134.9	39.7	40.0
SO_2	4.3	21.6	0.7	26.6	36.1	-9.5	40.0
PM/PM_{10}	10.2	1.1	2.5	13.8	3.4	10.4	25/15
CO	158.0	7.7	36.9	202.6	20.4	182.2	100.0
VOC	6.5	0.4	10.6	17.5	1.1	16.4	40.0
H_2SO_4	0.3	2.0	0.1	2.4	0.8	1.6	7.0

Emissions are based on firing natural gas in the turbine for 8,147 hours/yr at 348 MMBTU/hr and natural gas in the duct burner for 2,628 hours/yr at 187 MMBTU/hr. Oil firing in the turbine is based on 219 hours/yr at 382.6 MMBTU/hr.

Turbine performance under natural gas firing is based on NO_x emissions of 25 ppmvd (corrected to 15 percent O2). Performance on oil firing is based on NO_x emissions of 42 ppmvd (corrected to 15 percent O2). SO_2 emissions are based on 0.5 percent sulfur.

Date of Receipt of a Complete Application

March 6, 1992

BACT Determination Requested by Applicant

Control Technology: Combustion efficiency for cogeneration CO control.

Emission Limits: 75 ppmvd CO (natural gas or No. 2 oil - 0.5% Sulfur max.)
(No request made for Boilers 4 and 5)

BACT Determined by the Department

Control Technology: Combustion efficiency for cogeneration CO control.

Emission Limits:

Turbine - Natural gas firing:	42 ppmvd CO
Turbine - No. 2 oil firing:	75 ppmvd CO
Maximum % Sulfur - No. 2 oil:	0.5 % S
Duct Burner - Natural gas:	0.15 lb CO/MMBTU
Boilers 4 & 5: (Gas/Oil)	10%/20% Opacity

BACT Determination Procedure

In accordance with F.A.C. Chapter 17-2, 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 control methods, systems and techniques. In addition, the regulations require 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 determinations 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.

A review of EPA's BACT/LAER Clearinghouse indicates that catalytic oxidation is the most stringent control technique. An oxidation catalyst control system allows unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F and reaches near completion (above 90%) at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than for thermal oxidation thus reducing the thermal energy required. The oxidation catalyst is typically located directly after the turbine or as an integral part of the steam generator. Catalyst size depends on the exhaust flow, temperature, and desired efficiency.

Catalytic oxidation for CO control has been employed in nonattainment areas and is considered to be LAER technology capable of reducing CO emissions to the 10 ppm range. Due to economics, applications of catalytic oxidation technology have thus far been limited to small cogeneration facilities burning natural gas. Oxidation catalysts have not been used on base-loaded fuel oil-fired turbines in simple cycle or combined cycle facilities since extended use of sulfur-containing fuel would result in increased corrosion. Also, trace metals in the fuel could poison catalysts during prolonged fuel oil firing.

Using the applicant's proposed CO emission level of 75 ppmvd, the total annualized cost of CO catalytic oxidation for this project is $508,156 with a cost effectiveness of about $1,970/ton of CO removed. The cost effectiveness is based on 87% efficiency (75 ppmvd to 10 ppmvd) and includes a heat rate penalty of 0.2% based on an energy loss of $50/MW associated with pressure drop across the catalyst. A review of previous BACT determinations indicates that $1,970/ton would not be prohibitive. However, the decision to require catalytic oxidation should be based on a cost/benefit analysis once compliance testing has been done. Therefore, the Department will propose initial BACT emission limits for CO consistent with recent BACT determinations for similar sources. These limits are to be revised, if necessary, upon evaluation of the compliance test data. The turbine limit proposed by the applicant for fuel oil operation (75 ppmvd) is more stringent than a recent BACT determination for similar sources (78 ppmvd).

Other Air Pollutants Not Subject to BACT Determination

The application indicates that emissions of other pollutants will not be subject to a BACT determination. The applicant narrowly escaped PSD review for NO_X by lowering firing rates, and since increased firing rates may be requested at some future date, the Department will require that retrofit costs associated with the applicant's decision not to make initial provisions for future installation of advanced catalytic control shall not be considered in any cost analysis required for any future requested increase in capacity.

Details of the Analysis May be Obtained by Contacting:

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

Recommended by:	Approved by:
C. H. Fancy (signature)	Carol M. Browner (signature)
C. H. Fancy, P.E., Chief Bureau of Air Regulation	Carol M. Browner, Secretary Dept. of Environmental Regulation
August 14 1992 Date	August 17 1992 Date

Florida Power
CORPORATION

RECEIVED
NOV 20 1995
BUREAU OF AIR REGULATION

November 15, 1995

Mr. Clair H. Fancy
Bureau of Air Regulation
Florida Department of Environmental Regulation
2600 Blair Stone Road, MS 5505
Tallahassee, FL 32399-2400

Re: University of Florida Cogeneration Facility - Alachua County
AC01-204652 and PSD-FL-181
Request to Amend Construction Permit

Dear Clair:

This correspondence is submitted to provide information requested in the Department's letter dated May 22, 1995, concerning Florida Power Corporation's (FPC's) request to amend the air construction and prevention of significant deterioration (PSD) permit application for the University of Florida cogeneration facility.

The Department's responses to FPC's request to the custom fuel monitoring schedule and Specific Condition No. 2 are acceptable. At this time, the Department's response to FPC's request to amend Specific Condition No. 3 is acknowledged. FPC still has considerable concerns regarding the issue of simultaneous testing and may pursue alternative(s) to accommodate our concerns as suggested in the Department's response.

Specific Condition No. 8

The Department's response cited that portion of the BACT determination that indicated PSD review for NO_x was not required by assuring that a significant net emissions increase did not occur for the project. The "netting out" of PSD is appropriate under the Department's rules in Chapter 62-212 F.A.C. It must be recognized, however, that the criterion for PSD review is based on whether the project had a significant net emissions increase as defined in Rule 62-212.500(2)(e)2, F.A.C. The emissions rates for determining a significant net emission increase are in tons/year and were regulated in the permit based on annual fuel usage (refer to Specific Condition No. 3 of the permit).

As discussed in FPC's request to amend the permit, the increase in heat input and maximum NO_x emissions is for an operating condition that would occur only for short durations. This condition occurs at a turbine inlet temperature of 45°F. The manufacturer's curve for fuel use as a function of turbine inlet temperature is attached. This manufacturer's curve was developed from data supplied by General Electric Company and adjusted for actual machine performance. As can be seen from this graph, the maximum heat input and emissions occur at 45°F. The actual performance during the initial compliance test is also presented on the graph. The actual heat input during the test was 97 percent of the maximum heat input for the turbine inlet temperature that was measured during the test [i.e., actual of 344.6 x 10^3 standard cubic feet (kscf)/hr versus a maximum of 355 kscf].

ENVIRONMENTAL SERVICES DEPARTMENT
H2G • 3201 Thirty-fourth Street South • P.O. Box 14042 • St. Petersburg, Florida 33733 • (813) 866-5151
A Florida Progress Company

To determine compliance with the lb/hr and ton/yr limits, the control system accounts for hourly and cumulative NO_x emissions using the following equation:

$$NO_x \text{ (lb/hr)} = 8.47830 - 17.33488 \times \text{SF Ratio} + 0.00014 \times \text{FF}$$

where: SF Ratio = Steam-to-Fuel Ratio
FF = Fuel Flow (kscf)

This equation was developed using multiple regression analysis and had an R-squared value of 0.98709. This R-squared value indicates that over 98 percent of the variability in the NO_x emissions is accounted for in this equation. The ideal R-squared value is 1.0. The equation will be used until the CEM is installed and certified as required under 40 CFR Part 75.

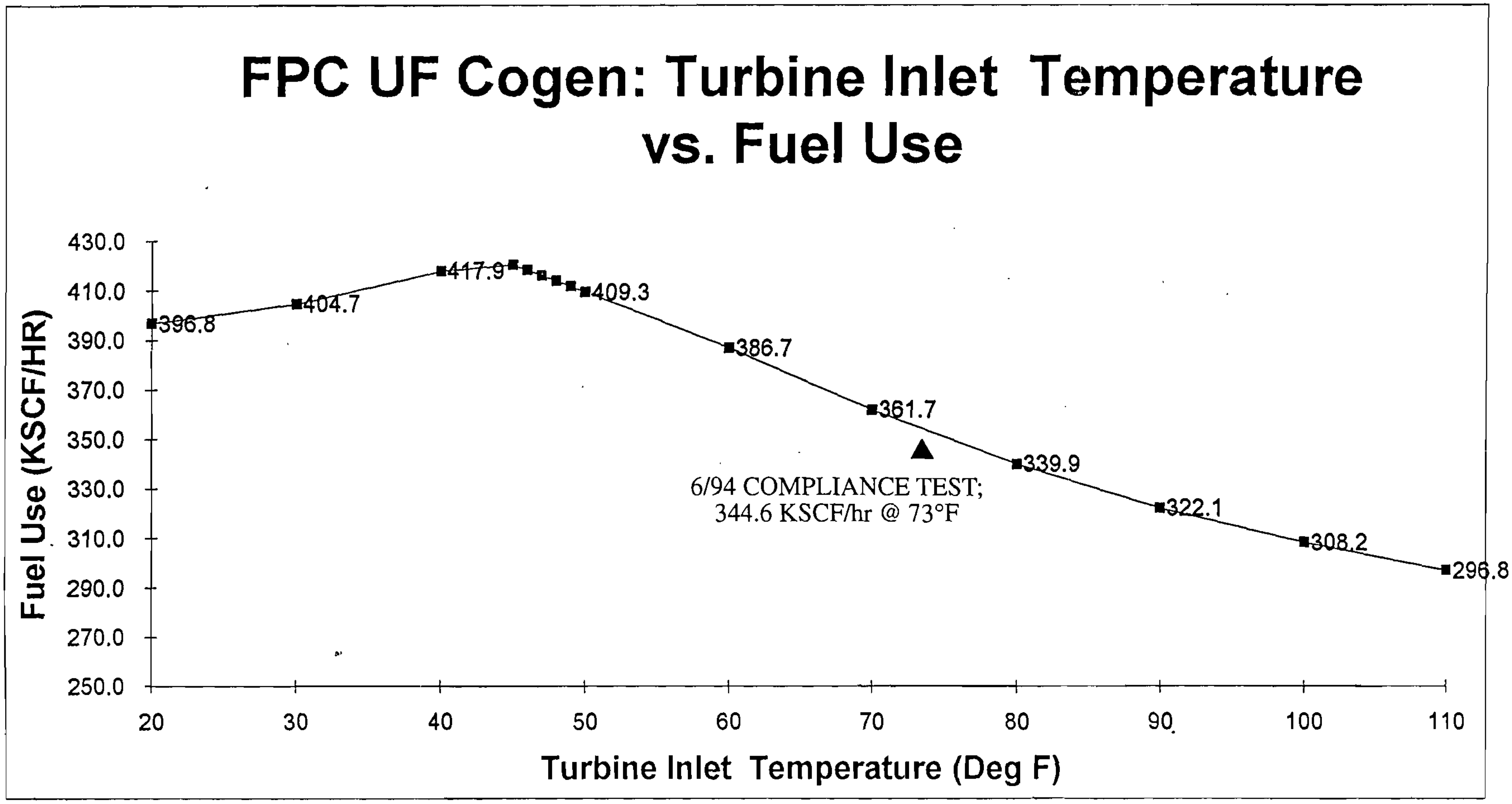
Please call me at (813) 866-5158 if you should have any questions.

Sincerely,

Scott H. Osbourn
Senior Environmental Engineer

Attachment

cc: Martin Costello, FDEP
Kennard Kosky, KBN
Robert Leetch, FDEP NE District



(Manufacturer Curves - Adjusted for Actual Machine Performance)

File

Department of Environmental Protection

Lawton Chiles
Governor

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

Virginia B. Wetherell
Secretary

September 13, 1995

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. Scott H. Osbourn
Senior Environmental Engineer
Florida Power Corporation
3201 Thirty-fourth Street South
St. Petersburg, Florida 33733

Re: Extension of Permits No. AC 01-204652, University of Florida Cogeneration Facility
AC 49-203114, Intercession City Facility

Dear Mr. Osbourn:

On August 30 the Department received your application letters, dated August 25, requesting an extension of the expiration date of the above referenced permits. The attached proposed rule language will, if adopted, extend the air construction permit by law. It is anticipated that the rule will be adopted in early September. If the rule is adopted within 90 days of receipt of your application, the Department will not be required to respond further. However, we will inform you upon adoption of the proposed rule.

If the rule, for any reason, is not adopted within 90 days of receipt of your application we will act upon your request in a timely manner. Please note that your air construction permit is valid until the Department acts upon your request.

Should you have any questions please contact me at (904) 488-1344.

Sincerely,

AA Linero

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

AAL/kw

cc: C. Collins, CD
E. Frey, NED
P. Reynolds, NED GBO
K. Kosky, KBN

NOTICE OF CHANGE IN PROPOSED RULE

DEPARTMENT OF ENVIRONMENTAL PROTECTION

DOCKET NO: 95-38R

CHAPTER TITLE:	CHAPTER NO.:
Operation Permits for Major Sources of Air Pollution	62-213
RULE TITLE:	RULE NO.:
Permit Applications	62-213.420

The Department has made a change to the proposed rule which appeared in the Florida Administrative Weekly, Volume 21, Number 30, dated July 28, 1995, page 4958, so that the following section(s) will read as set forth below:

62-213.420 Permit Applications

(1)(a)1.a. Acid Rain Sources will submit applications for the entire source by June 15, 1996 ~~January 1, 1996~~. The Acid Rain Part of each such application, however, shall be submitted no later than January 1, 1996.

b.(ii) June 15, 1996 ~~February 1, 1996~~, otherwise.

c. All other sources subject to the permitting requirements of this chapter will submit applications by June 15, 1996 ~~February 1, 1996~~.

2. Except as provided at Rule 62-213.420(1)(a)4., F.A.C., ~~except for sources that are subject to the Florida Electrical Power Plant Siting Act (FEPPSA),~~ a source that commences operation after January 1, 1996, must file an application for an operation permit under this chapter ninety days before expiration of the source's construction permit, but no later than 180 days after commencing operation. Except as provided at Rule 62-213.420(1)(a)4., F.A.C., a~~A~~ source that has applied for an Electrical Power Plant Siting Certification prior to January 1, 1996, but has not but has not been issued the certification as of that date, or a source that has been issued an Electrical Power Plant Siting Certification prior to January 1, 1996, but has not commenced operation by that date, shall file an application for an operation permit under this c~~C~~hapter ~~no later than~~ 180 days after commencing operation. Sources subject to the FEPPSA that apply for Electrical Power Plant Siting Certification subsequent to January 1, 1996, may, at their option, ~~shall~~ apply for a permit under the provisions of this chapter at the same time the Florida Power Plant Siting Certification application is submitted.

4. The expiration dates of all air construction permits for Title V sources that expire between September 1, 1995, and November 1, 1996 ~~September 1, 1996~~, are hereby extended to the later of November 1, 1996, or 240 days after commencing operation ~~September 1, 1996~~. Facilities with such air construction permits which have not commenced operation on January 1, 1996, shall apply

for a permit under the provisions of this chapter on the later of September 1, 1996, or 180 days after commencing operation.
Specific Authority: 403.061, 403.087, F.S.
Law Implemented: 403.061, 403.0872, F.S.
History: New 11-28-93; Amended 4-62-94; Formerly 17-213.420; Amended 11-23-94, 4-2-95, ________.

NAME OF PERSON ORIGINATING PROPOSED RULE: Howard L. Rhodes, Director, Division of Air Resources Management
NAME OF SUPERVISOR OR PERSON WHO APPROVED THE PROPOSED RULE: Virginia B. Wetherell, Secretary
DATE PROPOSED RULE APPROVED: July 17, 1995

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1. ☐ Addressee's Address
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Consult postmaster for fee.

3. Article Addressed to:
Mr. Scott H. Osbourn
Senior Environmental Engineer
Florida Power Corporation
3201 Thirty-fourth Street South
St. Petersburg, Florida 33733

4a. Article Number
Z 127 632 515

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

7. Date of Delivery
5/14/95

5. Signature (Addressee)
M. Williams

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.

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No Insurance Coverage Provided
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UNITED STATES POSTAL SERVICE

Sent to Mr. Scott H. Osbourn	
Street and No. Senior Environmental Eng	
P.O., State and ZIP Code 3201 34th St. S St Petersburg FL 33733	
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 AC01-204652 AC49-203114 Title V extension	

PS Form 3800, March 1993

Florida Power
CORPORATION

RECEIVED
AUG 30 1995
Bureau of
Air Regulation

August 25, 1995

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

Re: Florida Power Corporation
University of Florida Cogeneration Facility
Permit Extension to Accommodate Title V

Dear Mr. Linero:

Due to the extensions of time for submitting Title V applications and the modification request we have under review, the above-referenced facility construction permit (AC 01-204652) and backup boiler operating permits (AO 01-214826, -214828, -214829, -214830, and -214831) require an extension to accommodate the Title V application due date. The Title V permit application for this source is currently due on January 1, 1996, and DEP has indicated that the application submittal deadline may be extended further, until June 15, 1996. As a consequence, an extension of the construction and operating permits referenced above till September 15, 1996 is requested. An extension till September 15, 1996 will allow for any future delays in the Title V application due dates.

If you should have any questions concerning the above, please feel free to contact me at (813) 866-5158.

Sincerely,

Scott H. Osbourn
Senior Environmental Engineer

cc: Clair Fancy, FDEP
Ernest Frey, FDEP NE District
Patricia Reynolds, FDEP NE District GBO
Ken Kosky, KBN

ENVIRONMENTAL SERVICES DEPARTMENT
H2G • 3201 Thirty-fourth Street South • P.O. Box 14042 • St. Petersburg, Florida 33733 • (813) 866-5151
A Florida Progress Company

Department of
Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

file

May 22, 1995

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. W. Jeffrey Pardue, Director
Environmental Service Department
Florida Power Corporation
P. O. Box 14042
St. Petersburg, Florida 33733

Dear Mr. Pardue:

RE: University of Florida Cogeneration Facility Alachua County
AC01-204652 and PSD-Fl-181
Request for Amendment of Construction Permit

The Department is in receipt of your March 31 letter requesting to incorporate the EPA approved custom fuel monitoring schedule and to amend Specific Conditions No. 2, No. 3, and No. 8 of the above mentioned permit. This permit was issued under a stipulated settlement (OGC case No. 91-1113). The Department has evaluated your request and determines the following:

CUSTOM FUEL MONITORING SCHEDULE:

FPC'S REQUEST:

To incorporate the EPA approved custom fuel monitoring schedule for sulfur in natural gas.

DEPARTMENT'S RESPONSE:

The Department will amend the permit to incorporate the fuel monitoring schedule. The attached EPA custom fuel monitoring schedule shall be part of this permit.

SPECIFIC CONDITION NO.2

FPC'S REQUEST:

To delete reference to boiler No. 2 with no increases in the current cap for typ of NO_X for boilers No. 4 and 5.

DEPARTMENT'S RESPONSE:

Based on discussion with Company personnel, we understand FPC will withdraw this request and will use a rental boiler and the emergency order if needed. The Department's Office of General Counsel will review the draft order.

SPECIFIC CONDITION No.3

FPC'S REQUEST:

An Alternate to the NSPS testing requirements for the Subpart Db duct burner was proposed which involved combining the NO_X emission limits from the turbine and the duct burner. You provided a draft letter from the Department to EPA which proposed to demonstrate compliance with the duct burner NSPS NO_X emission standards (0.2 lb/MMBtu) without conducting a Method 20 upstream of the duct burner.

DEPARTMENT'S RESPONSE:

o Subpart Db establishes NO_X emission limits for the gas fired duct burner (0.2 lb/MMBtu pursuant to 40 CFR 60.44b) and Method 20 is specified upstream and down stream of the duct burner to demonstrate compliance (40 CFR 60.46b).

o 40 CFR 60.8(e)(1) requires the owner or operator of an affected facility to provide or cause to be provided, performance testing facilities including sampling ports adequate for test methods applicable to such facility.

o The requested alternate testing procedure must be reviewed pursuant to Rule 62-297.620, F.A.C., Exceptions and Approval of Alternate Procedures and Requirements (attached). FPC should provide the information required in Rule 62-297.620, F.A.C.

o The Department intends to deny the request to combine the emission limits from the turbine and duct burner unless and until an approved alternate sampling procedure is obtained from the Department's Emissions Monitoring Section. These are separate NSPS emissions units (Subpart GG and Subpart Db) and current NSPS regulations require that compliance be demonstrated for each emissions unit. The draft letter to EPA will not be sent. We understand that a second (revised) draft letter to EPA will be sent by FPC to the Department for review.

o The Department intends to amend AC01-203652/PSD-FL-181 to require NO_X and CO testing prior to obtaining the operating permit. Compliance testing on the duct burner will not be required annually since this emissions unit emits less than 100 tpy of NO_X or CO and there are significant difficulties with conducting the required Method 20 upstream of the duct burner. This will allow additional time for FPC to resolve the duct burner compliance test issues.

SPECIFIC CONDITION No. 8

FPC'S REQUEST:

To increase heat input rate from the turbine by 10% and corresponding increases in lb/hr of NO_X with no increases in tpy. FPC indicated that tpy NO_X limits would be demonstrated using the water-to-fuel monitor until 1996 when a NO_X CEMS would be used in place of the water/fuel monitor. The NO_X CEMS will be installed to meet the requirements of 40 CFR Part 75.

DEPARTMENT'S RESPONSE:

o The revised BACT determination for PSD-FL-181 established BACT for CO only. NO_X was not triggered for PSD review. There were 134.9 tpy of NO_X offsets listed from shutting down units 1, 2, and 3. The net increase in emissions totaled 39.7 tpy, just 0.3 tpy below the significance level for PSD review. From that BACT determination:

> "The application indicates that emissions of other pollutants will not be subject to a BACT determination. The applicant narrowly escaped PSD review for NO_X **by lowering firing rates**, and since increased firing rates may be requested at some time in the future, the Department will require that retrofit costs associated with the applicant's decision not to make initial provisions for future installation of advanced catalytic control shall not be considered in any cost analysis required for any future requested increase in capacity".

o BACT for similar combustion turbines when PSD-FL-181 was under review was 15 ppmvd @ 15% oxygen for gas firing to be obtained by 1997 or 1998. These emission levels were thought to be achievable using dry low NO_X combustor technology or SCR. This BACT, 15 ppmvd @ 15% oxygen, has been demonstrated currently using dry low NO_X burners. The NO_X standard in PSD-FL-181 was set at 25 ppmvd @ 15% oxygen for natural gas.

o The requested increase in lb/hr of NO_X emissions constitutes a modification. If approved, the Department would reissue the construction permit and public notice this action.

o The following information is requested to help the Department resolve this request. Please describe how FPC determined that increased heat rates, and corresponding increased NO_x emission rates, are achievable based on the initial performance test. Provide manufactures curves and example calculations. Please describe how tpy of NO_x are monitored for each emissions unit. State if any F factors will be used when the NO_x CEMS system is used for NO_x tpy monitoring. Supply example calculations and state all assumptions for these calculations. Describe fuel and process monitoring associated with the NO_x monitoring.

Submit any written inquiries or additional information to me at the above address. If you have any questions or need clarification on any of these items, please call Martin Costello at (904)488-1344.

Sincerely,

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

CHF/mc/h

attachments: Mr. Pardue's letter of March 31, 1995
EPA's custom fuel monitoring schedule guidance
Rule 62-297.620, F.A.C.

cc: Robert Leetch, NED
John Reynolds
Mike Harley
Morton Benjamin
Martin Costello

62-297.620 Exceptions and Approval of Alternate Procedures and Requirements.

(1) The owner or operator of any emissions unit subject to the provisions of this chapter may request in writing a determination by the Secretary or his/her designee that any requirement of this chapter (except for any continuous monitoring requirements) relating to emissions test procedures, methodology, equipment, or test facilities shall not apply to such emissions unit and shall request approval of an alternate procedures or requirements.

(2) The request shall set forth the following information, at a minimum:

(a) Specific emissions unit and permit number, if any, for which exception is requested.

(b) The specific provision(s) of this chapter from which an exception is sought.

(c) The basis for the exception, including but not limited to any hardship which would result from compliance with the provisions of this chapter.

(d) The alternate procedure(s) or requirement(s) for which approval is sought and a demonstration that such alternate procedure(s) or requirement(s) shall be adequate to demonstrate compliance with applicable emission limiting standards contained in the rules of the Department or any permit issued pursuant to those rules.

(3) The Secretary or his/her designee shall specify by order each alternate procedure or requirement approved for an individual emissions unit source in accordance with this section or shall issue an order denying the request for such approval. The Department's order shall be final agency action, reviewable in accordance with Section 120.57, Florida Statutes.

(4) In the case of an emissions unit which has the potential to emit less than 100 tons per year of particulate matter and is equipped with a baghouse, the Secretary or the appropriate Director of District Management may waive any particulate matter compliance test requirements for such emissions unit specified in any otherwise applicable rule, and specify an alternative standard of 5% opacity. The waiver of compliance test requirements for a particulate emissions unit equipped with a baghouse, and the substitution of the visible emissions standard, shall be specified in the permit issued to the emissions unit.

If the Department has reason to believe that the particulate weight emission standard applicable to such an emissions unit is not being met, it shall require that compliance be demonstrated by the test method specified in the applicable rule.

Specific Authority: 403.061, F.S.
Law Implemented: 403.021, 403.031, 403.061, 403.087, F.S.
History: Formerly 17-2.700(3); Amended 6-29-93; Formerly 17-297.620; Amended 11-23-94.

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- Write "Return Receipt Requested" on the mailpiece below the article number.
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Consult postmaster for fee.

3. Article Addressed to:
Mr. W. Jeffrey Pardue Director
Environmental Service Dept.
Fla. Power Corp.
PO Box 14042
St. Pete, Fl 33733

4a. Article Number
Z 311 902 897

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

7. Date of Delivery MAY 30 1995

5. Signature (Addressee) W. Williams

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**

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Sent to Jeffrey Pardue	
Street and No. Fla Power Corp	
P.O. State and ZIP Code St. Pete, 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	5-26-95

4C01-204652
PSO-F1-181

PS Form **3800**, March 1993

Florida Power
CORPORATION

March 31, 1995

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

Dear Mr. Fancy:

Re: UF Cogeneration Facility
AC01-204652; PSD-FL-181; Alachua County
Request for Amendment of Construction Permit

This correspondence and attached application are submitted to request some minor changes to the construction permit issued for the University of Florida (UF) Cogeneration Facility. The source is a nominal 43-megawatt (MW) cogeneration facility located adjacent to the University of Florida Central Heating Plant in Gainesville, Alachua County, Florida. The cogeneration facility consists of one combustion turbine (CT) exhausting through a heat recovery steam generator (HRSG). The primary fuel for the CT is natural gas with a maximum fuel input of 367.9 thousand cubic feet per hour (Mcf/hr). Distillate fuel oil is used for the CT only as backup. The transition duct from the CT to the HRSG was permitted with duct burners (DBs) having a maximum fuel (natural gas) input of 197.7 Mcf/hr.

The construction permit was issued August 17, 1992, and expires October 1, 1995. Initial compliance tests were performed on June 3 and 4, 1994, and test results indicate that compliance was demonstrated for all units. However, detailed review of these tests and an inspection of the facility revealed some areas where changes to permit conditions are necessary. Changes to Specific Conditions 2, 3 and 8 are requested. Please be advised, however, that this request for amendments does not constitute any change in total emissions from the facility. The initial tests for the facility demonstrated that the CT and DBs can achieve the basis of the nitrogen oxides (NO_x) emission limit. This is an extremely low emission rate given the energy efficiency of the CT.

Further, in response to New Source Performance Standard (NSPS) requirement 40 CFR 60.334(b), Florida Power Corporation (FPC) has requested a customized fuel monitoring schedule. The EPA has indicated concurrence with FPC's approach and the Department has indicated that this request would require a permit amendment. All pertinent correspondence on this issue from FPC, the Department and EPA Region IV is presented in Attachment 1 to this letter.

The following paragraphs present a discussion of the amendments requested for each of the specific conditions. Attachment 2 contains a mark-up of these conditions with the revisions requested.

ENVIRONMENTAL SERVICES DEPARTMENT
H2G • 3201 Thirty-fourth Street South • P.O. Box 14042 • St. Petersburg, Florida 33733 • (813) 866-5151
A Florida Progress Company

Specific Condition 2

This condition sets forth the emission limits for the facility (see attached Specific Condition). As discussed in the construction permit application, the CT selected for this project is the most efficient of all CTs and is the newest aircraft-derivative CT available from General Electric (i.e., the LM 6000). Indeed, when the application was submitted, there were no operating data on this machine while achieving the performance and emission guarantees proposed for this project. The initial testing of the CT indicated several areas where performance has been higher than expected. The maximum fuel flow rate of the CT is slightly higher than that initially specified by the manufacturer (GE). Accordingly, an increase in the short-term [pounds per hour (lb/hr)] NOx emission rate for the CT to 39.6 lb/hr is requested based on a requested increase in heat input (see Specific Condition 3). The basis for the limit is still 25 parts per million by volume, dry (ppmvd) corrected to 15 percent O_2.

Specific Condition 3

It is requested that the heat input be increased based on the performance tests. The maximum fuel usage rate to the turbine when firing natural gas in the current permit is 367.9 Mcf/hr. The maximum operating condition is at 45°F with a fuel input of 420.3 Mcf/hr and is based on GE data and the test results. During the compliance tests, the CT averaged 97 percent of the maximum heat input based on CT inlet temperature conditions. The requested maximum heat input corresponds to the maximum emission limit requested (See discussion for Specific Condition 2 above).

Specific Condition 8

It is requested that this condition be amended to delete the reference to boiler no. 2. FPC proposes to continue operation of boiler no. 2, which is equipped to fire natural gas as its primary fuel. FPC proposes that the same fuel use restrictions apply to this boiler as currently apply to boilers 4 and 5. Therefore, there would be no increase in emissions since the facility will demonstrate compliance with its annual emissions limits in tons per year.

Also, as a result of discussions between FPC and the Department, a draft Emergency Order has been prepared for the Department's review. This order would allow a back-up boiler to be used in an emergency (e.g., in the event that the cogeneration facility and the backup boilers become inoperable) in order to meet the steam demands required for the University of Florida and Shands Hospital.

Finally, a draft letter is enclosed regarding an alternative approach for demonstrating compliance with the NSPS for cogeneration or combined cycle systems with duct firing. This letter represents the understanding reached between FPC and the Department and is meant for the Department's use in obtaining concurrence from the EPA. Please contact Mr. Scott Osbourn if you should have any questions at (813) 866-5158. As always, your consideration in this matter is appreciated.

Sincerely,

W. Jeffrey Pardue, C.E.P.
Director, Environmental Services Department

Attachments

ATTACHMENT A

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

AUG 14 1987

OFFICE OF
AIR AND RADIATION

MEMORANDUM

SUBJECT: Authority for Approval of Custom Fuel Monitoring Schedules Under NSPS Subpart GG

FROM: John B. Rasnic, Chief
Compliance Monitoring Branch

TO: Air Compliance Branch Chiefs
Regions II, III, IV, V, VI and IX

Air Programs Branch Chiefs
Regions I-X

The NSPS for Stationary Gas Turbines (Subpart GG) at 40 CFR 60.334(b)(2) allows for the development of custom fuel monitoring schedules as an alternative to daily monitoring of the sulfur and nitrogen content of fuel fired in the turbines. Regional offices have been forwarding custom fuel monitoring schedules to the Stationary Source Compliance Division (SSCD) for consideration since it was understood that authority for approval of these schedules was not delegated to the Regions. However, in consultation with the Emission Standards and Engineering Division, it has been determined that the Regional Offices do have the authority to approve Subpart GG custom fuel monitoring schedules. Therefore it is no longer necessary to forward these requests to Headquarters for approval.

Over the past few years, SSCD has issued over twenty custom schedules for sources using pipeline quality natural gas. In order to maintain national consistency, we recommend that any schedules Regional Offices issue for natural gas be no less stringent than the following: sulfur monitoring should be bimonthly, followed by quarterly, then semiannual, given at least six months of data demonstrating little variability in sulfur content and compliance with §60.333 at each monitoring frequency; nitrogen monitoring can be waived for pipeline quality natural gas, since there is no fuel-bound nitrogen and since the free nitrogen does not contribute appreciably to NO_x emissions. Please see the attached sample custom schedule for details. Given the increasing trend in the use of pipeline quality natural gas, we are investigating the possibility of amending Subpart GG to allow for less frequent sulfur monitoring and a waiver of nitrogen monitoring requirements where natural gas is used.

Where sources using oil request custom fuel monitoring schedules, Regional Offices are encouraged to contact SSCD for consultation on the appropriate fuel monitoring schedule. However, Regions are not required to send the request itself to SSCD for approval.

If you have any questions, please contact Sally M. Farrell at FTS 382-2875.

Attachment

cc: John Cronshaw
George Walsh
Robert Ajax
Earl Salo

BEST AVAILABLE COPY

Enclosure

Conditions for Custom Fuel Sampling Schedule for Stationary Gas Turbine

1. Monitoring of fuel nitrogen content shall not be required while nat gas is the only fuel fired in the gas turbine.

2. Sulfur Monitoring

 a. Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. The reference methods are: ASTM D1072-80; ASTM D3031-81; ASTM D3246-81; and ASTM D4084-82 as referenced in 40 CFR 60.335(b)(2).

 b. Effective the date of this custom schedule, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then sulfur monitoring shall be conducted once per quarter for six quarters.

 c. If after the monitoring required in item 2(b) above, or herein, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

 d. Should any sulfur analysis as required in items 2(b) or 2(c) ab[ove] indicate noncompliance with 40 CFR 60.333, the owner or operato[r] shall notify the State Air Control Board) of such excess emissions and the custom schedule shall be re-examined by the Environmental Protection Agency. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

3. If there is a change in fuel supply, the owner or operator must notify the State of such change for re-examination of this custom schedule. A substantial change in fuel quality shall be considered as a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

4. Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of three years, and be avai[lable] for inspection by personnel of federal, state, and local air polluti[on] control agencies.

TOTAL

March 23, 1995

Jewell A. Harper, Chief
Air Enforcement Branch
U.S. Environmental Protection Agency, Region IV
345 Courtland Street, N.E.
Atlanta, GA 30365

DRAFT

proposed by FPC

Dear Ms. Harper:

RE: Demonstrating Compliance with NSPS
Combustion Turbines and Duct Burners
University of Florida Cogeneration Facility PSD-FL-181

The Florida Department of Environmental Protection (FDEP) has been approached by Florida Power Corporation (FPC), which owns and operates the University of Florida Cogeneration facility, regarding an alternative approach for demonstrating compliance with the NSPS for combined cycle systems with duct firing. The UF facility has a nominal 43 megawatt (MW) combustion turbine (CT) firing primarily natural gas that exhausts through a heat recovery steam generator (HRSG). In the transition duct between the CT and HRSG, there are duct burners (DB) with a maximum heat input capability greater than 100 million (MM) Btu/hr while firing only natural gas. An air construction/Prevention of Significant Deterioration (PSD) permit was issued in August, 1992 and the facility become operational in 1994. The only exhaust point is through a stack connected to the HRSG. The NSPS applicable to the UF facility include Subpart GG (for the combustion turbine) and Subpart Db (for the duct burners). The only pollutant at issue is NOx emissions. The NSPS for the combustion turbine is 75 parts per million volume-dry conditions (ppmvd) corrected to 15 percent oxygen and adjusted for heat rate; the NSPS for the duct burners is 0.2 lb/MMBtu heat input.

As you are aware, the UF facility like so many other cogeneration facilities that have been recently permitted in Florida, have emission limitations established that are substantially lower than NSPS levels. For example, the UF facility has a CT lb/hr emission limit based on 25 ppmvd corrected to 15 percent oxygen and a DB lb/hr limit based on 0.1 lb/MMBtu. The CT limit is about 5 times lower than the NSPS while the DB limit is one half of the NSPS.

In order to demonstrate compliance with the NSPS for this facility, there is an implied requirement in Subpart Db and Method 20 to perform simultaneous sampling of the turbine exhaust and the exhaust stack to determine compliance with NSPS. This requirement can be difficult, if not impossible to perform and introduce costly testing procedures. It is this Department's position that the simultaneous testing requirement is unnecessary and that the source should be presumed in compliance with the NSPS, if the source can demonstrate that its combined CT/DB NOx emissions using EPA Method 20 at the single exhaust stack are less than the emissions that would be allowed under either <u>Subpart GG or Db</u>. The following information obtained for the UF Cogeneration facility demonstrates this conclusion.

CT: the applicable NSPS under Subpart GG (i.e., 75 ppmvd @ 15% O_2; corrected for heat rate) during conditions of the initial compliance test would produce an emission rate of 92 lb/hr.

DB: the applicable NSPS under Subpart Db (i.e., 0.2 lb/MMBtu) during the conditions of the initial compliance test would produce an emission rate of 42 lb/hr (for 210.2 MMBtu/hr heat input).

CT/DB: the combined NOx emissions during the initial compliance test were 29.3 lb/hr while both the CT and DB were operating. The CT NOx emissions were 21.6 ppmvd @ 15% O_2 (ISO) and the DB emissions were 0.05 lb/MMBtu. The combined applicable NSPS would be 134 lb/hr.

As noted above, since the testing demonstrated, using Method 20, that the combined NOx emissions (i.e., 29.3 lb/hr) were less than either Subpart GG or Db emissions limits, compliance with the NSPS requirements should be considered met. Therefore, the implied requirement in Subpart Db and Method 20 to perform simultaneous sampling of the turbine exhaust and the exhaust stack to determine compliance with NSPS is not necessary.

It is also the Department's position that if the combined CT/DB NOx emission limits established in the permit are met during annual compliance testing, the simultaneous testing to demonstrate continued compliance with NSPS would not be required for this source.

The Department would appreciate the Region's concurrence with this approach. A written response is respectfully required as this approach may apply to other cogeneration facilities and its implementation would assist the Department in evaluating compliance with these projects. Please call me at (904) 488-1344 if you have any questions.

Sincerely,

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

cc: Scott Osbourn, FPC
Ken Kosky, KBN
John Reynolds, BAR
Martin Costello, BAR
Mort Benjamin, FDEP

ATTACHMENT 1

Customized Fuel Monitoring Schedule

ATTACHMENT 2

Proposed Changes to Permit Conditions

PERMITTEE:
Florida Power Corporation

Permit Number: AC 01-204652
PSD-FL-181
Expiration Date: December 31, 1994

SPECIFIC CONDITIONS:

2. Emissions from this facility shall not exceed the limits listed below:

PROPOSED CHANGES

Pollutant	Source	Fuel	Basis of Limit	lbs/hr	tons/yr
NOx	Turbine	Gas	EBM*:25 ppmvd @ 15% O2	~~35.0~~ 39.6	142.7
	Turbine	Oil	EBM*:42 ppmvd @ 15% O2	66.3	7.3 +
	TURBINE / D.Burner	Gas	EBM*:0.1 lb/MMBTU FOR D.B.	~~18.7~~ 58.3	~~24.6~~ 167.3
SO2	Turbine 2C	Oil	BACT:0.5% Sulfur Max.	-	-
	Boiler 4	Oil	BACT:0.5% Sulfur Max.	-	-
	Boiler 5	Oil	BACT:0.5% Sulfur Max.	-	-
VE	Turbine	Gas/Oil	Equivalent of mass EBM*	10%/20% opacity**	
	D.Burner 2E	Gas	" " "	10% opacity	
	Boiler 4	Gas/Oil	" " "	10%/20% opacity**	
	Boiler 5	Gas/Oil	" " "	10%/20% opacity**	
CO	Turbine	Gas	BACT:42 ppmvd	38.8	158.0
	Turbine	Oil	EBA***:75 ppmvd	70.5	7.7 +
	D.Burner	Gas	BACT:0.15 lb/MMBTU****	~~28.1~~ 66.9	~~56.9~~ 194.9 +

*EBM: Established by manufacturer
**Except for one 6-minute period per hour of not more than 27% opacity
***EBA: Established by applicant
****BACT limit proposed by applicant in Table A-2 of application FOR D.B.
+ TOTAL CONTRIBUTION FROM TURBINE AND DUCT BURNER

3. Fuel consumption rates and hours of operation for the turbine and duct burner shall not exceed those listed below:

PROPOSED CHANGE

	Natural Gas			No. 2 Fuel Oil		
	M ft3/hr*	MM ft3/yr	hrs/yr*	M gal/hr*	M gal/yr	hrs/yr*
Turbine	420.3 ~~367.9~~	2997.2**	8146.8**	2.9	635.1	219.0**
Duct Burner	197.7	519.5	2628.0	0	0	0

*Based on maximum firing rates. Units may run at lower rates for more hours within annual fuel limits.

**An additional 1.9 hours/yr operation on natural gas will be allowed for each 1.0 hour/yr that fuel oil is not burned (up to 219 x 1.9 hours/yr), in which case, the emission limits in Specific Condition No. 2 shall be adjusted accordingly.

PERMITTEE:
Florida Power Corporation

Permit Number: AC 01-204652
PSD-FL-181
Expiration Date: December 31, 1994

SPECIFIC CONDITIONS:

If test results from the turbine and duct burner show that it is unlikely that NO_x limits can be met, a revised BACT determination for NO_x shall also be considered. The Department may revise the BACT determination to require installation of such technology if so indicated by the revised BACT cost/benefit analysis. If the permittee has elected not to provide for future addition of such technology in the initial construction and later applies for a permit modification to increase capacity, the retrofit costs associated with not making provisions for such technology (initially) shall not be considered by the Department in the retrofit cost analysis required for the future expansion.

8. Boilers Nos. 1, ~~2~~ ~~and~~ 3 shall permanently cease operation upon receipt of the operation permit for the cogeneration facility. X

9. 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).

10. 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).

Issued this 17th day
of August, 1992

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Carol M. Browner

Carol M. Browner, Secretary

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

ORDER
GRANTING TEMPORARY
USE OF EMERGENCY BACKUP BOILER
CAPABILITY TO MEET COMMITMENT
FOR UNINTERRUPTIBLE STEAM DEMAND

Florida Power Corporation (FPC) having requested issuance of an order to permit use of an Emergency Backup Boiler at its University of Florida Cogeneration Site and the Department having been fully advised in the premises, the Secretary finds as follows:

FINDINGS OF FACT

1. FPC has a commitment to the University of Florida, including Shands Hospital, to provide an uninterruptible supply of steam.

2. In the unlikely event that the cogeneration facility and either Backup Boiler 4 or 5 (or both) become inoperable, an emergency backup steam supply source will be required. This is because Backup Boilers 4 and 5 are both necessary to provide replacement steam for loss of the cogeneration facility and cannot supply all steam potentially necessary if required to serve as backups for each other.

CONDITIONS OF USE OF EMERGENCY BACKUP BOILER

1. In accordance with the Florida Statutes, Chapter 120.59 pertaining to Orders, the Secretary is authorized to grant exceptions from air construction permits and can allow the use of an Emergency Backup Boiler in order that Florida Power Corporation (FPC) may meet its commitment for uninterruptible steam demand when the primary sources of steam supply are inoperable.

2. In the event that FPC is unable to meet steam demand to the University of Florida due to the inoperability of any of the primary sources of steam supply (i.e., the cogeneration facility and Backup Boilers 4 and 5), the Secretary authorizes FPC to operate an additional boiler as an Emergency Backup.

3. The use of such an Emergency Backup shall not result in an increase in permitted air emissions over the limits prescribed by the Department in Permit No. AC01-204652 (PSD-FL-181).

ORDER

Subject to the Conditions of Use of Emergency Backup Boiler cited above, the Secretary hereby grants approval to FPC for use of an Emergency Backup Boiler at its University of Florida Cogeneration site. DONE AND ENTERED THIS ________ day of________, 199__, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

____
VIRGINIA WETHERELL
Secretary

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32301
Telephone: (904) 488-4805

File: u\:UFORDER

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Department of Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

December 5, 1994

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. W. Jeffrey Pardue, C.E.P.
Florida Power Corporation
P. O. Box 14042
St. Petersburg, Florida 33733

RE: UF Cogeneration Project
AC01-204652, PSD-FL-181
Request for Permit Amendment

Dear Mr. Pardue:

The Bureau of Air Regulation has reviewed the above referenced request and determined that it will require a new permit as discussed in the December 1 meeting. The customized fuel monitoring request can be processed separately, but the $250 processing fee must be submitted as indicated in our letter dated May 11, 1994. If you have any questions, please call Patty Adams at (904)488-1344.

Sincerely,

Patricia G. Adams

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

CHF/pa

cc: John Reynolds

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. W. Jeffrey Parude, C.E.P.
Florida Power Corporation
P. O. Box 14042
St. Petersburg, Florida 33733

4a. Article Number

P 872 562 687

4b. Service Type

☐ Registered ☐ Insured
XX Certified ☐ COD
☐ Express Mail ☐ Return Receipt for Merchandise

7. Date of Delivery

DEC 9 1994

5. Signature (Addressee) Brian L Nill[illegible]

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 872 562 687

UNITED STATES POSTAL SERVICE

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

Sent to Mr. W. Jeffrey Pardue	
Street and No. P. O. Box 14042	
P.O., State and ZIP Code St. Petersburg, FL 33733	
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: 12/07/94 AC01-204652, PSD-FL-181	

PS Form 3800, JUNE 1991

Florida Power
CORPORATION

RECEIVED
NOV 30 1994
Bureau of Air Regulation

November 28, 1994

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

Dear Mr. Fancy:

Re: UF Cogeneration Project
AC01-204652; PSD-FL-181; Alachua County
Request for Amendment of Construction Permit

This correspondence is submitted to request some minor changes to the construction permit issued for the University of Florida (UF) cogeneration facility. The source is a nominal 43-megawatt (MW) cogeneration facility located adjacent to the University of Florida Central Heating Plant in Gainesville, Alachua County, Florida. The cogeneration facility consists of one combustion turbine (CT) exhausting through a heat recovery steam generator (HRSG). The primary fuel for the CT is natural gas with a maximum fuel input of 367.9 thousand cubic feet per hour (Mcf/hr). Distillate fuel oil is used for the CT only as backup. The transition duct from the CT to the HRSG was permitted with duct burners (DBs) having a maximum fuel (natural gas) input of 197.7 Mcf/hr.

The construction permit was issued August 17, 1992, and expires December 31, 1994. Initial compliance tests were performed on June 3 and 4, 1994, and test results indicate that compliance was demonstrated for all units. However, detailed review of these tests and an inspection of the facility revealed some areas where changes to permit conditions are necessary. Changes to Specific Conditions 2, 3 and 8 are requested. Further, in response to New Source Performance Standard requirement 40 CFR 60.334(b), FPC has requested a customized fuel monitoring schedule. The EPA has indicated concurrence with FPC's approach and the Department has indicated that this request would require a permit amendment. All pertinent correspondence on this issue from FPC, the Department and EPA Region IV is presented in Attachment 1 to this letter.

Please be advised, however, that this request for amendments does not constitute any change in total emissions from the facility. The initial tests for the facility demonstrated that the CT and DBs can achieve the basis of the nitrogen oxides (NO_x) emission limit. This is an extremely low emission rate given the energy efficiency of the CT.

The following paragraphs present a discussion of the amendments requested for each of the specific conditions. Attachment 2 contains a mark-up of these conditions with the revisions requested.

Specific Condition 2

This condition sets forth the emission limits for the facility (see attached Specific Condition). As discussed in the construction permit application, the CT selected for this project is the most efficient of all CTs and is the newest aircraft-derivative CT available from General Electric (i.e., the LM 6000). Indeed, when the application was submitted, there were no operating data on this machine while achieving the performance and emission guarantees proposed for this project. The initial testing of the CT indicated several areas where performance has been higher than expected. The maximum fuel flow rate of the CT is slightly higher than that initially specified by the manufacturer (GE).

Based on the initial tests and final configuration of the facility, the following changes are requested.

1. CT Emissions of NO_x - Increase short-term [pounds per hour (lb/hr)] CT emission rate to 39.6 lb/hr based on a requested increase in heat input (see discussion for Specific Condition 3). The basis for the limit is still 25 parts per million by volume, dry (ppmvd) corrected to 15 percent O_2.

2. Specify CT/DB Emission Limits - It is requested that the Department consider changing the specification of individual limits for DBs to emission limits applicable to the CT/DBs operating together. As noted above, there will be no increase in annual emissions or in the basis upon which the hourly rate is determined (i.e., 0.1 lb/MMBtu) with this requested change to the permit. The reasons for this request are fourfold.

   First, the large volume flow rate of the CT could produce erroneous results when trying to determine compliance with a DB only emissions limit. The combination of large flow rate and smaller emission contribution from the DBs can produce substantial apparent errors when none exist.

   Secondly, determining the emission status of the facility will be much easier for both the operators and FDEP by having specific limits for the CT and CT/DB combination. Since the facility will install a continuous emission monitoring (CEM) system for NO_x, and this system will be reporting total NO_x downstream of both units, determining the emission status would be directly evident.

   Third, the DBs cannot be operated without the CT; therefore, it is logical to specify emission limits for the combination rather than separately.

   Finally, the original compliance testing was performed using simultaneous testing at the CT exhaust and the stack to determine compliance with NSPS Subpart Db requirements. Since the emissions from the DB were very low compared with the NSPS limit (i.e., 0.04 lb/MMBtu from the test compared with the NSPS limit of 0.2 lb/MMBtu) and there is no explicit applicable NSPS requirement to perform annual testing for NSPS purposes, a separate DB emission limit and implicit testing are unnecessary. If, for example, the emissions from the DB approached the NSPS limit, a combined limit would be exceeded. A combined limit would be 58.3 lb/hr; if the DB were at NSPS levels, then its contribution would be 64 percent of the total leaving only a 36 percent contribution from the CT. This is equivalent to a CT contribution of 20.9 lb/hr, which is not technically possible with steam injection. The combined limit also would demonstrate compliance with the basis of the BACT determination. Therefore, the emissions cannot exceed the original emission basis of 25 ppmvd at 15 percent O_2 for the CT and 0.1 pound per million British thermal units (lb/MMBtu) for the DBs.

   Also, please note that many of the emission limits for the facility, including NO_x , were not established as BACT. Since the facility is replacing, to a large extent, the steam generated by the old University of Florida steam plant, emission offsets were credited to the new cogeneration plant, thus netting out of PSD review.

3. Emergency Steam Demands - The steam demands of the University of Florida necessitate that the facility, which includes Boilers 4 and 5, provide an uninterrupted steam supply. This uninterrupted steam is required for Shands Hospital. In the unlikely event that the cogeneration facility and Boilers 4 and/or 5 become inoperable, an emergency backup source is required. This is because Boilers 4 and 5 are both necessary to provide replacement steam for loss of the cogeneration facility (i.e., they are not backups for each other). It is requested that the permit allow provisions to accommodate this emergency backup condition. This could be accomplished by either allowing the continued operation of one of the three boilers currently scheduled for retirement or by allowing the use of a rented boiler, when needed. The same fuel use restrictions would apply to this boiler as Boilers 4 and 5; there would be no increase in emissions since the facility must demonstrate compliance with its annual emissions limits in tons per year.

Specific Condition 3

It is requested that the heat input be increased based on the performance tests. The maximum fuel usage rate to the turbine when firing natural gas in the current permit is 367.9 Mcf/hr. The maximum operating condition is at 45°F with a fuel input of 420.3 Mcf/hr and is based on GE data and the test results. During the compliance tests, the CT averaged 97 percent of the maximum heat input based on CT inlet temperature conditions. The requested maximum heat input corresponds to the maximum emission limit requested (See discussion for Specific Condition 2, Item 1 above).

Specific Condition 8

It is requested that this condition be amended to reflect continued operation of one of these three boilers, if necessary.

Please contact Mr. Scott Osbourn if you should have any questions, at (813) 866-5158. As always, your consideration in this matter is appreciated.

Sincerely,

J. Michael Kennedy for

W. Jeffrey Pardue, C.E.P.
Director, Environmental Services Department

/mrb
Attachments

ATTACHMENT 1

Customized Fuel Monitoring Schedule

ATTACHMENT 2

Proposed Changes to Permit Conditions

PERMITTEE:
Florida Power Corporation

Permit Number: AC 01-204652
PSD-FL-181
Expiration Date: December 31, 1994

SPECIFIC CONDITIONS:

2. Emissions from this facility shall not exceed the limits listed below:

PROPOSED CHANGES

Pollutant	Source	Fuel	Basis of Limit	lbs/hr	tons/yr
NOx	Turbine	Gas	EBM*:25 ppmvd @ 15% O2	~~35.0~~ 39.6	142.7
	Turbine	Oil	EBM*:42 ppmvd @ 15% O2	66.3	7.3 +
	TURBINE / D.Burner	Gas	EBM*:0.1 lb/MMBTU FOR D.B.	~~18.7~~ 58.3	~~24.6~~ 167.3
			combined got 29.3 Lb/hr		
SO2	Turbine 2c	Oil	BACT:0.5% Sulfur Max.	-	-
	Boiler 4	Oil	BACT:0.5% Sulfur Max.	-	-
	Boiler 5	Oil	BACT:0.5% Sulfur Max.	-	-
VE	Turbine	Gas/Oil	Equivalent of mass EBM*	10%/20% opacity**	
	D.Burner 2F	Gas	" " "	10% opacity	
	Boiler 4	Gas/Oil	" " "	10%/20% opacity**	
	Boiler 5	Gas/Oil	" " "	10%/20% opacity**	
CO	Turbine	Gas	BACT:42 ppmvd 10 Lb/hr	38.8	158.0
	Turbine	Oil	EBA***:75 ppmvd	70.5	7.7 +
	D.Burner	Gas	BACT:0.15 lb/MMBTU****	~~28.1~~ 66.9	~~96.9~~ 194.9

*EBM: Established by manufacturer

**Except for one 6-minute period per hour of not more than 27% opacity

***EBA: Established by applicant

****BACT limit proposed by applicant in Table A-2 of application FOR D.B.

+ TOTAL CONTRIBUTION FROM TURBINE AND DUCT BURNER

3. Fuel consumption rates and hours of operation for the turbine and duct burner shall not exceed those listed below:

PROPOSED CHANGE

	Natural Gas			No. 2 Fuel Oil		
	M ft3/hr*	MM ft3/yr	hrs/yr*	M gal/hr*	M gal/yr	hrs/yr*
Turbine	~~367.9~~ 420.3	2997.2**	8146.8**	2.9	635.1	219.0**
Duct Burner	197.7	519.5	2628.0	0	0	0

Tested @ 202 MCF/h

*Based on maximum firing rates. Units may run at lower rates for more hours within annual fuel limits.

**An additional 1.9 hours/yr operation on natural gas will be allowed for each 1.0 hour/yr that fuel oil is not burned (up to 219 x 1.9 hours/yr), in which case, the emission limits in Specific Condition No. 2 shall be adjusted accordingly.

210 MM BTU/hr

208 MM BTU/hr

$\frac{29 \text{ Lb/hr}}{210 \text{ MMBTU/hr}} = .14$ Lb/MMBTU

PERMITTEE:
Florida Power Corporation

Permit Number: AC 01-204652
PSD-FL-181
Expiration Date: December 31, 1994

SPECIFIC CONDITIONS:

If test results from the turbine and duct burner show that it is unlikely that NO_x limits can be met, a revised BACT determination for NO_x shall also be considered. The Department may revise the BACT determination to require installation of such technology if so indicated by the revised BACT cost/benefit analysis. If the permittee has elected not to provide for future addition of such technology in the initial construction and later applies for a permit modification to increase capacity, the retrofit costs associated with not making provisions for such technology (initially) shall not be considered by the Department in the retrofit cost analysis required for the future expansion.

8. Boilers Nos. 1, ~~2~~ and 3 shall permanently cease operation upon receipt of the operation permit for the cogeneration facility.

9. 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).

10. 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).

Issued this 17th day
of August, 1992

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Carol M. Browner, Secretary

Florida Power
CORPORATION

David L. Miller
Senior Vice President
Corporate Services

October 21, 1994

TO WHOM IT MAY CONCERN

Subject: Letter of Authorization

Please be advised that W. Jeffrey Pardue, Director, Environmental Services Department, Sharon K. Momberg, Manager of Waste Management Programs, Kent D. Hedrick, Manager of Water Programs, J. Michael Kennedy, Manager of Air Programs, and Patricia Quets, Environmental Project Manager, are authorized to represent Florida Power Corporation in matters relating to necessary permits and reporting documentation required from regulatory authorities in the areas of air, water, power plant site certifications and transmission line certifications, or hazardous and solid materials issues.

Sincerely,

David L. Miller

DLM:bb

3201 Thirty-fourth Street South · P.O. Box 14042, St. Petersburg, Florida 33733 · (813) 866-5701
A Florida Progress Company

Department of Environmental Protection

Northeast District
7825 Baymeadows Way, Suite B200
Jacksonville, Florida 32256-7590

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

CERTIFIED - RETURN RECEIPT

August 4, 1994

RECEIVED
AUG 15 1994
Environmental Svcs
Department

Mr. W. Jeffery Pardue, C.E.P.
Florida Power Corporation
P.O.Box 14042 (H2G)
St. Petersburg, Florida 33733

Dear Mr. Pardue:

Alachua County - AP
Florida Power Corp. at UF

Emission Unit	Permit No.	ID No.
Cogen GT Plant	AC01-204652	31JAX01000101

This permit is extended to 06-02-95 to coordinate this emissions unit with the submittal of the Title V source (facility) permit application which shall be submitted by 04-02-95 per FAC Rule 17-213.420(1)(a)1.a.

Since this extension is in lieu of processing an operation permit application for a short-term operation permit, the testing required by this permit shall be performed initially and annually thereafter.

Any party to this Order (permit) has the right to seek judicial review of the permit pursuant to Section 120.68, Florida Statutes, by filing 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 30 days from the date this Notice is filed with the Clerk of the Department.

If there are any questions, please contact Johnny Cole at (904) 448-4310, Ext. 236.

Sincerely,

Ernest E. Frey, P.E.
EBR Director of District Management

EEF:RJB:JCC

Memorandum

Florida Department of
Environmental Protection

Patty
FILE
FPC
UNIV OF FL

TO: Chris Kirts

FROM: Mike Harley

DATE: June 29, 1994

SUBJECT: Emission Test Report for Florida Power Corporation's Combined Cycle System at the University of Florida

The Emissions Monitoring Section received a copy of the test report for the compliance test of Florida Power Corporation's (FPC) combined cycle unit at the University of Florida. Martin Costello [Emissions Monitoring Section] was one of the Department representatives who witnessed the emission testing on Friday, June 3, 1994. We have reviewed the test report and note the following deviations:

(1) The sampling site prior to the duct burner did not include a sufficient number of ports to permit sampling in accordance with EPA Method 20. This is a substantial deviation from EPA Method 20 requiring prior approval of an alternate sampling procedure pursuant to Rule 17-297.620, F.A.C. It is also a violation of 40 CFR 60.8(e).

(2) The test runs at the sampling site prior to the duct burner were conducted with a multipoint probe which had a sealed end and holes drilled along the length of the probe. This is a substantial deviation from EPA Method 20 requiring prior approval of an alternate sampling procedure pursuant to Rule 17-297.620, F.A.C. EPA Method 20 requires the use of an open ended tube of sufficient length to traverse the sample points and the collection of an individual sample at each traverse point.

(3) EPA Method 20 requires the collection of diluent samples at each traverse point for an equal period of time in order to identify any points where stratification may occur within the duct. EPA Method 20 then requires the collection of NOx samples for an equal period of time at the eight traverse points where the pollutant is least dilute. The use of the multipoint probe and single sampling port did not permit sampling at each traverse point. Further, there is no assurance that an equal sample aliquot was collected at each of the sample points. Again this is a substantial deviation from EPA Method 20 requiring prior approval of an alternate sampling procedure pursuant to Rule 17-297.620, F.A.C.

An owner or operator who wishes to deviate from the applicable source testing requirements is required to file a formal request for approval of an alternate sampling procedure pursuant to Rule 17-297.620, F.A.C. The request should be submitted to the Division of Air Resources Management in Tallahassee and will be reviewed by the Emissions Monitoring Section. In the case of a source subject to the NSPS, the EPA would need to review and concur with the request before it could be approved. The required procedures remain in effect until the Department formally acts to approve the request.

It would be appropriate to reject the test results and consider an enforcement action for the 40 CFR 60.8(e) violation. A copy of a recent EPA letter concerning another combined cycle system is enclosed for your information. If you have any questions, please call me or Martin Costello (904) 488-1344.

cc: C. Fancy
J. Pennington
J. Brown
M. Benjamin

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET. N.E.
ATLANTA, GEORGIA 30365

JUN 15 1994

4APT-AEB

RECEIVED
JUN 21 1994
Environmental Svcs
Department

Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of
Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Approval of NSPS Custom Fuel Monitoring Schedules for: Florida Power Corporation (FPC), University of Florida Cogeneration Project, PSD-FL-181

Dear Mr. Fancy:

This is to acknowledge a letter from Mr. Scott H. Osbourn of FPC dated April 5, 1994, requesting approval of customized fuel monitoring schedules for the above referenced project. This letter was addressed to you and a copy was sent to the U.S. Environmental Protection Agency (EPA). Since the authority for implementing §60.334(b) of 40 CFR Part 60, Subpart GG has not been delegated to the State of Florida, we have reviewed FPC's custom fuel monitoring schedule.

Based on our review we have determined that the proposed schedule is acceptable, because it conforms to custom fuel monitoring guidance memo issued by EPA headquarters on August 14, 1987. A copy of this memo was included in FPC's request as attachment.

If you have any questions regarding this letter, please contact Mr. Mirza P. Baig of my staff at 404/347-5014.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, & Toxics
Management Division

cc: Scott H. Osbourn, FPC

Best Available Copy

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

Petty-file

JUN 15 1994

RECEIVED

JUN 20 1994

Bureau of
Air Regulation

4APT-AEB

Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of
Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Re: Approval of NSPS Custom Fuel Monitoring Schedules for: Florida Power Corporation (FPC), University of Florida Cogeneration Project, PSD-FL-181

Dear Mr. Fancy:

This is to acknowledge a letter from Mr. Scott H. Osbourn of FPC dated April 5, 1994, requesting approval of customized fuel monitoring schedules for the above referenced project. This letter was addressed to you and a copy was sent to the U.S. Environmental Protection Agency (EPA). Since the authority for implementing §60.334(b) of 40 CFR Part 60, Subpart GG has not been delegated to the State of Florida, we have reviewed FPC's custom fuel monitoring schedule.

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Sincerely yours,

Jewell A. Harper

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, & Toxics
Management Division

cc: Scott H. Osbourn, FPC

RECEIVED

JUL 05 1994

Emissions Monitoring

Florida Department of
Environmental Protection

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

Lawton Chiles
Governor

Virginia B. Wetherell
Secretary

May 11, 1994

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. Scott H. Osbourn
Senior Environmental Engineer
Florida Power Corporation
P. O. Box 14042
St. Petersburg, FL 33733

Dear Mr. Osbourn:

RE: Florida Power Corporation
University of Florida Cogeneration Project
AC 01-204652, PSD-FL-181
Customized Fuel Monitoring Schedule

The Bureau of Air Regulation has reviewed your April 5, 1994, letter concerning the above referenced request and determined that it will require a permit amendment. As soon as the processing fee of $250 is received, we will begin processing your request. If you have any questions, please call Patty Adams at (904)488-1344.

Sincerely,

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

CHF/pa

Printed on recycled paper.

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.

RECEIVED
MAY 19 1994
Bureau of
Air Regulation

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. Scott H. Osbourn
Senior Environmental Engineer
Florida Power Corporation
P. O. Box 14042
St. Petersburg, Florida 33733

4a. Article Number
P 872 563 635

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

7. Date of Delivery
MAY 16 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 872 563 635

UNITED STATES POSTAL SERVICE

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

Sent to Mr. Scott Osbourn	
Street and No. P. O. Box 14042	
P.O., State and ZIP Code St. Petersburg, FL 33733	
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: 5/13/94 AC 01-204652, PSD-FL-181	

PS Form 3800, JUNE 1991

Florida Power
CORPORATION

April 5, 1994

RECEIVED
APR 11 1994
Bureau of
Air Regulation

Mr. C. H. Fancy, Chief
Bureau of Air Permitting
Department of Environmental Protection
2600 Blair Stone Road
Tallahassee, FL 32399

Dear Mr. Fancy:

Re: Florida Power Corporation (FPC)
University of Florida Cogeneration Project
AC 01-204652; PSD-FL-181
Customized Fuel Monitoring Schedule

The FPC University of Florida Cogeneration Project has been permitted under the above-referenced PSD permit. This unit consists of an advanced combustion turbine with a heat recovery steam generator (HRSG). The combustion turbine is subject to New Source Performance Standards (NSPS-40 CFR 60, Subpart GG). 40 CFR 60.334(b) requires the owner/operator of any combustion turbine to monitor the sulfur and nitrogen content of the fuel as follows: 1) If the turbine fuel is supplied by a bulk storage tank, then the sulfur and nitrogen content are to be determined whenever new fuel is transferred into the bulk storage tank, and 2) If the turbine fuel is supplied without an intermediate bulk storage tank then daily monitoring of the sulfur and nitrogen content of the fuel is required.

Since the natural gas used by the combustion turbine does not pass through an intermediate bulk storage tank, FPC is hereby requesting a customized fuel monitoring schedule as allowed by 40 CFR 60.334(b)(2). While firing natural gas, FPC requests the following customized fuel monitoring schedule which was developed based on an EPA guidance memorandum (Attachment A):

1. Monitoring of natural gas nitrogen content shall not be required in accordance with page 2 of the EPA guidance memorandum attached.

2. Sulfur Monitoring

   a. Analysis for sulfur content of the natural gas shall be conducted using one of the EPA approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternate method. The reference methods are: ASTM D1072-80; ASTM D3031-81; ASTM D3245-81; and ASTM D4048-82 as referenced in 40 CFR 60.335(b)(2).

b. Effective on the approval date of the customized fuel monitoring schedule, sulfur monitoring shall be conducted twice a month for six months. If this monitoring shows little variability in the sulfur content and indicates consistent compliance with 40 CFR 60.333, then sulfur monitoring shall be conducted once per quarter for six quarters.

c. If the monitoring required by 2(b), above, of the sulfur content of the natural gas shows little variability and the calculated sulfur dioxide emissions represent consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample analysis shall be conducted twice per year. This monitoring shall be conducted during the first and third quarters of each calendar year.

d. Should any sulfur analysis as required by items 2(b) or 2(c) above indicate noncompliance with 40 CFR 60.333, FPC will notify the Department of Environmental Protection of such excess emission and the customized fuel monitoring schedule shall be reexamined. The sulfur content of the natural gas will be monitored weekly during the interim period while this monitoring schedule is being reexamined.

3. FPC will notify the Department of Environmental Protection of any change in natural gas supply for reexamination of this monitoring schedule. A substantial change in natural gas quality (i.e., sulfur content varying greater than 10 grains/1000 cf gas) shall be considered as a change in natural gas supply. Sulfur content of the natural gas will be monitored weekly during the interim period when this monitoring schedule is being reexamined.

4. Records of sampling analysis and natural gas supply pertinent to this monitoring schedule shall be retained by FPC for a period of three years, and be available for inspection by appropriate regulatory personnel.

5. FPC will obtain the sulfur content of the natural gas from Florida Gas Transmission Company at its Brooker Lab.

Data from natural gas at the Brooker Lab site is considered representative of the sulfur content of the natural gas at the University of Florida site since there is no additional entry point for sulfur or other elements/compounds which may affect the quality of the natural gas.

If you or your staff have any questions about this request, please call me at (813) 866-5158.

Sincerely,

Scott H. Osbourn
Senior Environmental Engineer

Attachments

cc/attach: Mike Harley, FDEP
David McNeal, Region IV, EPA
G. Reynolds
G. Cole, NE Dist

APPENDIX A

ATTACHMENT A

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

AUG 14 1987

OFFICE OF
AIR AND RADIATION

MEMORANDUM

SUBJECT: Authority for Approval of Custom Fuel Monitoring Schedules Under NSPS Subpart GG

FROM: John B. Rasnic, Chief
Compliance Monitoring Branch

TO: Air Compliance Branch Chiefs
Regions II, III, IV, V, VI and IX

Air Programs Branch Chiefs
Regions I-X

The NSPS for Stationary Gas Turbines (Subpart GG) at 40 CFR 60.334(b)(2) allows for the development of custom fuel monitoring schedules as an alternative to daily monitoring of the sulfur and nitrogen content of fuel fired in the turbines. Regional Offices have been forwarding custom fuel monitoring schedules to the Stationary Source Compliance Division (SSCD) for consideration since it was understood that authority for approval of these schedules was not delegated to the Regions. However, in consultation with the Emission Standards and Engineering Division, it has been determined that the Regional Offices do have the authority to approve Subpart GG custom fuel monitoring schedules. Therefore it is no longer necessary to forward these requests to Headquarters for approval.

Over the past few years, SSCD has issued over twenty custom schedules for sources using pipeline quality natural gas. In order to maintain national consistency, we recommend that any schedules Regional Offices issue for natural gas be no less stringent than the following: sulfur monitoring should

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be bimonthly, followed by quarterly, then semiannual, given at least six months of data demonstrating little variability in sulfur content and compliance with §60.333 at each monitoring frequency; nitrogen monitoring can be waived for pipeline quality natural gas, since there is no fuel-bound nitrogen and since the free nitrogen does not contribute appreciably to NO_x emissions. Please see the attached sample custom schedule for details. Given the increasing trend in the use of pipeline quality natural gas, we are investigating the possibility of amending Subpart GG to allow for less frequent sulfur monitoring and a waiver of nitrogen monitoring requirements where natural gas is used.

Where sources using oil request custom fuel monitoring schedules, Regional Offices are encouraged to contact SSCD for consultation on the appropriate fuel monitoring schedule. However, Regions are not required to send the request itself to SSCD for approval.

If you have any questions, please contact Sally M. Farrell at FTS 382-2875.

Attachment

cc: John Cronshaw
George Walsh
Robert Ajax
Earl Salo

BEST AVAILABLE COPY Enclosure

Conditions for Custom Fuel Sampling Schedule for Stationary Gas Turbines

1. Monitoring of fuel nitrogen content shall not be required while natu[ral] gas is the only fuel fired in the gas turbine.

2. Sulfur Monitoring

   a. Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for the measurement of sulfur in gaseous fuels, or an approved alternative method. The reference methods are: ASTM D1072-80; ASTM D3031-81; ASTM D3246-81; and ASTM D4084-82 as referenced in 40 CFR 60.335(b)(2).

   b. Effective the date of this custom schedule, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates consistent compliance with 40 CFR 60.333, then sulfur monitoring shall be conducted once per quarter for six quarters.

   c. If after the monitoring required in item 2(b) above, or herein, the sulfur content of the fuel shows little variability and, calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

   d. Should any sulfur analysis as required in items 2(b) or 2(c) abov[e] indicate noncompliance with 40 CFR 60.333, the owner or operator shall notify the State Air Control Board) of such excess emissions and the custom schedule shall be re-examined by the Environmental Protection Agency. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

3. If there is a change in fuel supply, the owner or operator must notify the State of such change for re-examination of this custom schedule. A substantial change in fuel quality shall be considered as a change in fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

4. Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of three years, and be availab[le] for inspection by personnel of federal, state, and local air pollution control agencies.

Florida Power
CORPORATION

March 25, 1994

Mr. Chris Kirts
Air Program Manager
Northeast District
7825 Bay Meadows Way, Suite B200
Jacksonville, Florida 32256

Dear Mr. Kirts:

Re: Compliance Test Notification for the University of Florida Cogeneration Project
DEP Permit No. AC 01-204652

As required by 40 CFR 60.8, Florida Power Corporation (FPC) is providing the Department of Environmental Protection (DEP) notification of the commencement of compliance testing of the new cogeneration facility at FPC's University of Florida electric generating station. The testing is scheduled to begin on April 25, 1994. If you recall, in a letter dated December 31, 1993, FPC had previously provided notification that testing was to have begun by January 31, 1994. The combustion turbine was damaged during initial startup and debugging and was shipped back to the factory for repair. The April 25, 1994 proposed test date assumes that the refurbished turbine will be received onsite for installation by April 4, 1994.

If you should have any questions concerning this notification, please feel free to contact me at (813) 866-5158.

Sincerely,

Scott H. Osbourn
Senior Environmental Engineer

cc: John Brown, DEP Tallahassee
Mike Harley, DEP Tallahassee
Mort Benjamin, DEP- Northeast District
Patricia Reynolds, Gainesville Air Programs
J. Harper, EPA

RECEIVED

MAR 30 1994

Bureau of
Air Regulation

Patty
File w/permit

Florida Power
CORPORATION

Certified Mail P 627 945 297

December 31, 1993

Mr. Chris Kirts
Air Program Manager, Northeast District
7825 Bay Meadows Way, Suite B200
Jacksonville, Florida 32256

Dear Mr. Kirts:

Re: Compliance Test Notification for the University of Florida Cogeneration Project
DEP Permit No. AC 01-204652

As required by 40 CFR 60.8, Florida Power Corporation (FPC) is providing the Department of Environmental Protection (DEP) notification of the commencement of compliance testing of the new cogeneration facility at FPC's University of Florida electric generating station. The testing is scheduled to begin on January 31, 1994.

A copy of the proposed test plan was received by your office on December 29, 1993. FPC is also submitting a copy of the proposed test plan to Mr. Mike Harley, of the DEP in Tallahassee, with his copy of this letter. Based upon discussions with Messrs. Mort Benjamin and Stan Mazur of your staff on December 30, 1993, FPC will attempt to schedule a pre-test meeting at your office within the next two weeks.

If you should have any questions or concerns, please feel free to contact me at (813) 866-5158.

Sincerely,

Scott H. Osbourn
Senior Environmental Engineer

RECEIVED

JAN 03 1994

Bureau of
Air Regulation

cc: John Brown, DEP Tallahassee
Mike Harley, DEP Tallahassee w/Enclosure

Florida Power
CORPORATION

Certified Mail P 627 945 298

December 31, 1993

Mr. Chris Kirts
Air Program Manager, Northeast District
7825 Bay Meadows Way, Suite B200
Jacksonville, Florida 32256

Dear Mr. Kirts:

Re: Compliance Test Notification for the University of Florida Cogeneration Project
DEP Permit No. AC 01-204652

As required by 40 CFR 60, Florida Power Corporation (FPC) is providing the Department of Environmental Protection (DEP) notification of the initial startup of the new cogeneration facility at FPC's University of Florida electric generating station. The initial startup occurred on December 17, 1993.

If you should have any questions or concerns, please feel free to contact me at (813) 866-5158.

Sincerely,

Scott H. Osbourn
Senior Environmental Engineer

cc: John Brown, DEP Tallahassee

Florida Power
CORPORATION

Certified Mail P 627 945 297

December 31, 1993

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Air Program Manager, Northeast District
7825 Bay Meadows Way, Suite B200
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Sincerely,

Scott H. Osbourn
Senior Environmental Engineer

Ken Harder

cc: John Brown, DEP Tallahassee
Mike Harley, DEP Tallahassee w/Enclosure

per David McNeal
EPA Region IV

CODE	REFERENCE	QUESTION	AFFECTED REGULATION	DETER-MINATION	DISCUSSION
A-41	Memo to R-IV (E. Reich to T. Gibbs) 23 August 77	Is the basis of the existing facility or the basis of the entire stationary source used in the calculation of the annual asset guideline repair allowance, which is referred to in the definition of capital expenditure in Section 60.2(bb)?	60.2 (bb)		To determine whether or not a modification has occurred due to an increase in production rate, compare the amount of money spent for physical or operational change to the existing facility to the product of the existing facility's basis and the annual asset guideline repair allowance for the existing facility. If more than one existing facility is located in the same stationary source and there is an increase in emissions from both facilities, use the basis and repair allowance of each separate existing facility for determining whether or not a modification has occurred.
A-42	Memo to R-IV (E. Reich to J. Wu) 29 Sept. 77	What procedure should be followed when an affected facility has not been performance tested in the 180 day period following startup due to shutdowns caused by equipment malfunction?	60.8(a)		Consider issuing a 113(a) order requiring the owner or operator to notify the Administrator upon restartup (by telephone; to be followed by confirmation in writing) and also requiring a performance test as soon as practicable thereafter but no later than 30 days after restartup. If the facility is unable to operate at the maximum production rate for the initial performance test, a subsequent performance test may be required when the facility achieves maximum production in order to assure compliance with the standard.
A-43	Memo to R-IV (E. Reich to F. Phillips) 30 Sept. 77	Same as A-39			See A-39
A-44	Memo to R-VII (E. Reich to E. Stephenson) 28 December 77	Is a steam generator whose capital cost of reconstruction is only 43% of the cost of a comparable new steam generator subject to NSPS due to reconstruction?	60.15	No	If the fixed capital cost (including all labor costs) of reconstructing the affected facility (as defined in the applicable subpart) is less than 50% of the cost of an entirely new affected facility, then the affected facility is not subject to NSPS.

FLORIDA POWER CORPORATION
UNIVERSITY OF FLORIDA COGENERATION SITE
FAX COVER SHEET

P. O. BOX 140660
GAINESVILLE, FL. 32614-0660

PHONE NO. (813) 384-7575
FAX NO. (813) 384-7576

TO: Mike Harley

DATE: 1-10-94

FROM:
Bob Anderson

Number of Pages 2
(Including Cover Sheet)

COMMENTS:

Operating Days
Bob Anderson
Scott Osborne
(904)374-2208

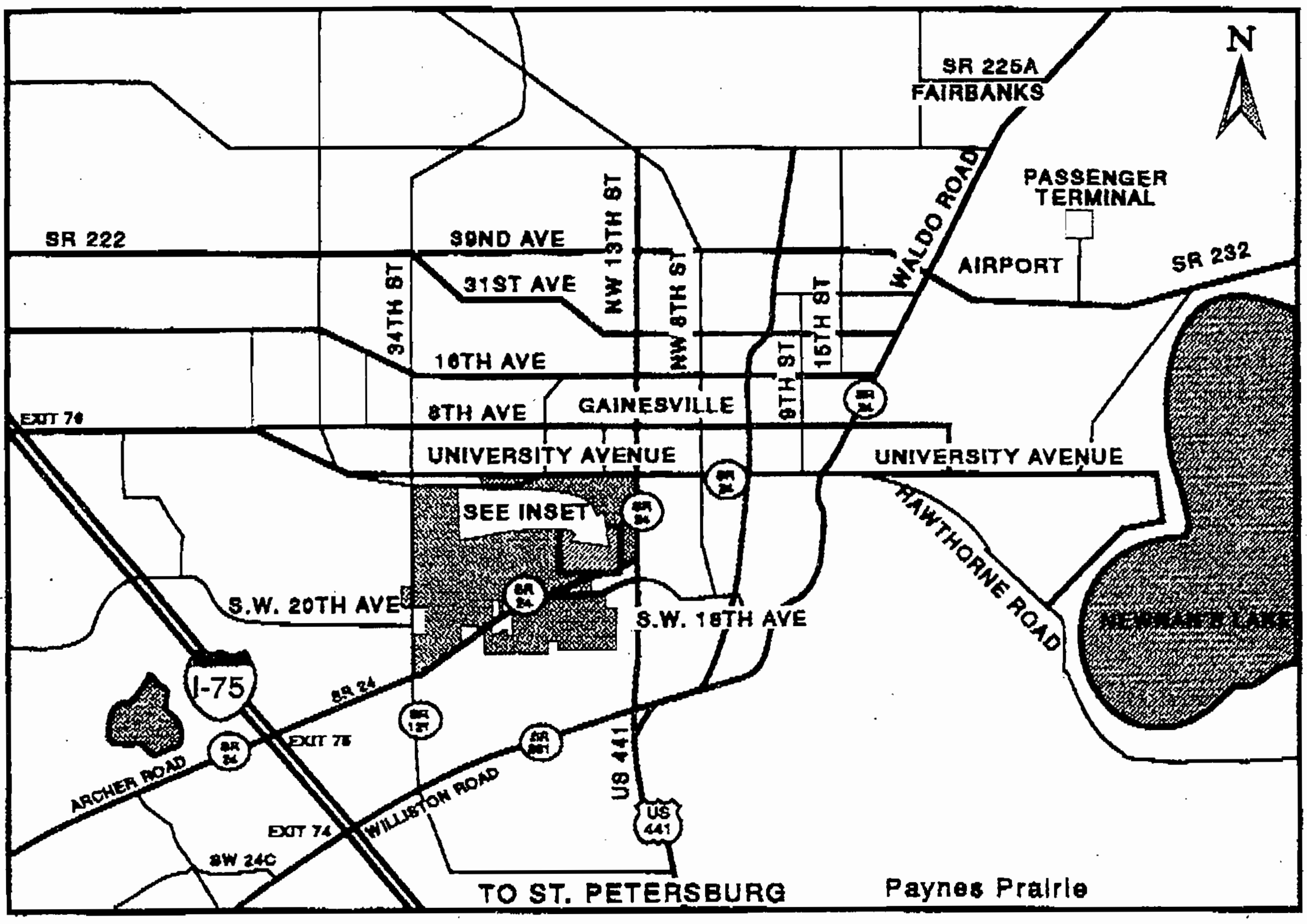
Testing Mtg

[illegible]

BEST AVAILABLE COPY

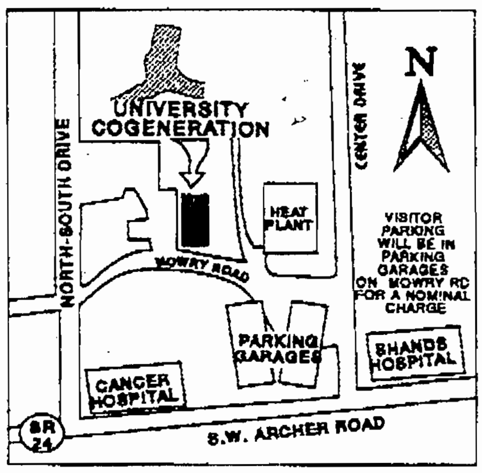
U. OF F. COGENERATION PLANT

FLORIDA POWER CORPORATION



Location:	Mowry Road, Gainesville, Fl
Mail Address:	P.O. Box 140660 Gainesville, FL 32614-0660
Nearest Airport:	Gainesville, FL
Driving from GOC:	North on I-75 to Gainesville. Take exit 75 (Archer Rd). Go east 7 traffic lights. Take left on North-South Drive. Go one block to Mowry Rd. Turn right and plant will be on left approx. one block.
Driving from airport:	Go west on Rt. 232 (NE 39th Ave.) Turn left on Rt. 441and follow until it merges with Rt. 24. Stay on Rt. 24 past Shands Hospital. Turn right on North-South Drive. Take first right onto Mowry Road and plant will be on left approx. one block.

Telephone:	Mail Code:	Microwave:
(904) 374-2208	GV44	226-7575



Subpart G.G.

NO_x Standard: $\% NO_x @ 15\% O_2 = 0.0075 \frac{(14.4)}{HR \text{ up to } 14.4 \text{ KJ/Watt-hr}} + F_N$

SO_2 Standard: $\% SO_2 @ 15\% O_2 = 15$ (Dry Basis)

TESTING: Nitrogen Content in Fuel — Approved method Accurate w/I 5%

NO_x → ISO equation $NO_x \%$ by volume @ $15\% O_2$ $= NO_{x\,observed} \cdot \left[P_r/P_o\right]^{0.5} \cdot e^{19(H_o - .00633)} \cdot \left[\frac{288}{T_a}\right]^{1.5}$ (& Corrected?)

measure:
1) combustor inlet P
2) Humidity ratio (T_w & T_d)
3) Ambient Temp
4) O_2 Concentration in stack

Graph: Develope curve @ ISO corrected Loads: 30, 50, 75, 100

Method 20 for NO_x, O_2, SO_2 (ASTM D 1072-80, 3031-81, 4084-82, 7246-81)

CEM SPANS: NO_x — 300 ppm

O_2 — 21%

Please Fax to Scott Osborne

(813) 866 4926

Scott Osborne

Fax (813) 866-4926 —

Martin Costello

→ NE District Mort. & Stan
Bob Anderson

Ken Koski - KBN - Engineer of Record.

Nox Cap.

FEB-08-'94 TUE 10:34

MESSAGE CONFIRMATION

P-9999

TERM ID:

TEL NO:

NO.	DATE	ST. TIME	TOTAL TIME	ID	DEPT CODE	OK	NG
622	02-08	10:32	00°01'21	813 866 4926		02	00

Scott Osborn.

FPC's Alternative

Kent Hedric → EPA to Allow
Combined Emissions limit on Duct burner?
6-8 wks to Rebuild

Dec 17 Clock Starts
180 DAY.

Call EPA for Determination
on 180 DAY clock
→ stops when unit Down?

Feb 16

Wtg

TEST PLAN

for

EXHAUST EMISSION MEASUREMENTS

from one

GENERAL ELECTRIC COMBUSTION GAS TURBINE WITH SUPPLEMENTAL FIRED DUCT BURNERS

at the

UNIVERSITY OF FLORIDA FACILITY

GAINESVILLE, FLORIDA

Prepared For

Florida Power Corporation

December 1993

Prepared by

Cubix Corporation

9225 Lockhart Hwy., Austin, Texas 78747
(512) 243-0202 FAX (512) 243-0222

TABLE OF CONTENTS

OVERVIEW

Exhaust emissions from one General Electric (GE) combustion turbine (CT) with supplementally fired heat recovery steam generator (HRSG) are to be tested to determine the quantity of emissions being vented to the atmosphere. The turbine to be tested is in service at the University of Florida facility in Gainesville, Florida, Alachua County. The purpose of this testing is to verify that the turbine demonstrates compliance with the applicable limits set forth by the Florida Department of Environmental Protection (FDEP), air quality permit number AC 01-204652 and PSD-FL-181. The testing will be conducted by Cubix Corporation of Austin, Texas. Table 1 provides background data pertinent to these tests.

The cogeneration unit consists of a GE Model LM 6000 combustion gas turbine (including an inlet air cooler) and a heat recovery steam boiler with supplementary firing duct burners. The turbine and duct burners are fired on pipeline grade natural gas only. The turbine is rated at 43.3 MW when firing natural gas.

NOx emissions from the turbine are controlled by steam injection. Testing will be conducted on the turbine at each of four separate load conditions to verify the steam injection rates at each load. In order to allow the determination of emissions by the duct burner only, two test conditions are required. The first condition tested would be with the combustion turbine (CT) operating at a stabilized full load with the duct burners off. The second condition tested would required the CT (at the same full load rate) and the duct burner to be fired. The NOx emissions from the duct burners would be calculated by subtracting the average NOx emission from the CT only test from the average NOx emission from the CT and duct burner joint fired test.

TABLE 1
Background Data

Sources	One GE Model LM 6000 gas combustion turbine with a supplementary firing HRSG. This turbine also has inlet air cooling capabilities.
Location:	University of Florida Mowry Road, Building No. 82 Gainesville, Florida
Applicable Permits and Regulations	FDEP Permit # AC 01-204652 PSD-FL-181, EPA 40 CFR 60 Subparts Db and GG
Emissions Test Coordinator:	Florida Power Corporation 3201 34th Street South St. Petersburg, Florida 33711 Attn: Albert Morneault, P.E. (813) 866-5162
Test Contractor:	Cubix Corporation 9225 Lockhart Highway Austin, Texas 78747 Attn: Rick J. Krenzke (512) 243-0202 TEL (512) 243-0222 FAX
Test Dates:	To be specified in transmittal letter.
Test Schedule:	To be specified in transmittal letter.

TEST MEASUREMENTS

Exhaust emission testing will be conducted on one GE Model LM 6000 gas combustion turbine with a supplementally fired heat recovery steam generator. Emission measurements will be made for NOx, CO, O_2, CO_2, and opacity on the turbine. Testing will also be performed on the joint firing of the turbine and duct burner to determine the contribution of NOx and CO from the duct burner. All measurements will be conducted while firing natural gas. Compliance tests will be run at 96% to 100% of the maximum capacity achievable for the average inlet air temperature observed during the compliance tests. The turbine manufactures capacity (MW) vs. inlet air temperature curves will be included in the compliance test report. Daily samples of the natural gas will be collected and analyzed for composition, total sulfur, heating value, and specific gravity. The emission testing will follow the applicable test methods described in the Environmental Protection Agency's (EPA) Code of Federal Regulations, Title 40, Part 60 Appendix A and the fuel analyses will follow analytical procedures set forth by American Society of Testing and Materials (ASTM). The specific test methods to be used are listed as follows:

should be As Fired

Exhaust Analyses

* EPA Method 1 for traverse point layout for the O_2 traverse points established by EPA Method 20.
* EPA Method 3a for O_2 and CO_2 concentrations.
* EPA Method 3b for F_0 calculations.
* EPA Method 9 for opacity observations.
* EPA Method 10 for CO concentrations.
* EPA Method 19 for mass emission, and stack flow rate calculations.
* EPA Method 20 for NOx and O_2 concentrations.

Fuel Analyses

* ASTM D 1945 for natural gas composition analysis.
* ASTM D 3588 for natural gas specific gravity and heating value (gross and net).
* ASTM D 3246 for total sulfur content of natural gas.

More detailed descriptions of each test method with any required test method adaptations, as they will be applied to the University of Florida emission tests, are outlined below.

Test Matrix

The test matrix to be used during these tests is depicted in detail in Table 2. Table 2 shows that testing will begin with measurement of the turbine only emissions. The first item during the turbine only tests will be the initial O_2 traverse during which O_2 and CO_2 are measured. Although the actual time of this test run will depend on the stack size, sample port configuration, and the results of Cubix's sample system response time test, it is anticipated that this procedure will require 88-minutes of sampling . This is based on the stack size requiring a 44 point traverse and Cubix's sample system response time being 1-minute or less. EPA Method 20 requires that the sample time at each traverse point be 1-minute plus the average sample system response time. This will result in a 44 point traverse for 2-minutes per point. The sample location for these tests will be from the exhaust stack of the CT/HRSG and the duct burners will be turned off. The O_2 traverse will be performed at the lowest load tested with steam injection. Appendix F contains a site-plan, stack drawing, and traverse point layout for this unit.

Following the initial O_2 traverse, turbine only emissions will be measured at four separate loads including minimum and maximum firing rates. The four load points will be determined in accordance with 40 CFR 60, Subpart GG, §60.335 (c) (2). These tests are required to satisfy the provisions of EPA Subpart GG and will be conducted from the CT/HRSG stack. Three test runs will be conducted at each of the four loads. Again, Cubix's sample system response time results will determine the actual test run times, but it is anticipated that each test run will consist of 24-minutes (i.e. eight traverse points for 3-minutes per point). NOx, O_2, CO_2, and CO emissions shall be measured instrumentally and SO_2 emissions shall be calculated using the results of the daily fuel analysis. Opacity tests will be conducted during both the CT and the joint fired tests for the time stipulated in 40 CFR 60.11.

Following the turbine only tests at full load, the duct burners shall be turned on to maximum firing rate and the joint fire emissions shall be measured. To satisfy the stipulations of EPA Subpart Db, it is necessary to determine the duct burner contribution to the NOx emissions. The FDEP permit also requires the measurement of the CO emission contribution by the duct burners. With the duct burners firing at maximum, and the turbine operating at the same full load (same MW) as tested prior to the joint firing tests, emissions of NOx and CO will again be measured in the CT/HRSG stack of the unit. In the event that the steam flow cannot be maintained, the CT and duct burner operation may have to be adjusted.

Mass emission rates of the turbine and the duct burners will be calculated by EPA Method 19 procedures. The emission rate from the turbine only are based on the fuel flow to the turbine, the fuel analysis and exhaust measurements made in the exhaust stack with the turbine only firing. Likewise, the emission rate of the joint firing of the turbine and duct burner are based on the fuel flow to both units, fuel analysis and exhaust measurements make in the CT/HRSG stack. The contribution of the duct burners will be determined by subtracting the turbine only emissions from the joint fired emissions. The contribution from the duct burners will be expressed in lbs/hr and lb/MMBtu for comparison with the permit limits and the NSPS allowable.

Exhaust Gas Sampling and Analyses

The stack gas analyses for NOx, CO, CO_2 and O_2 will be performed by continuous instrumental monitors. Table 3 lists the instruments, detection principles, and applicable ranges of those instruments. All instruments will be housed in an environmentally controlled, trailer-mounted, mobile laboratory. Data from these analyzers will be recorded on two 25-cm width, 3-pen strip chart recorders (Soltec 1243) operating at a speed of 30-cm/hr. A computer data logging system will also be provided to allow for convenient visual checking of emission concentrations. Calibration gases for these instruments will be provided in aluminum cylinders with the concentrations certified by the vendor (See *Quality Assurance Activities*).

The sampling and analysis system to be used for measurement of the above mentioned gaseous concentrations is depicted in Figure 1. Stack gas enters the system through a stainless steel probe with a glass wool filter. The sample is transported via 3/8-inch heat-traced Teflon® tubing to a specially designed stainless steel minimum-contact condenser which dries the sample without removing NOx. The sample is then passed to ground level through 3/8-inch Teflon® via a stainless steel/Teflon® diaphragm pump and into the sample manifold. From the manifold, the sample is partitioned to the analyzers through glass and stainless steel rotometers. The purpose of the rotometers is to ensure that the sample pressure and flow rate are equal to that used for the calibration gases.

Cubix will use a special alloy probe (Haynes Alloy 214) for the sampling of gaseous components. This material has a high yield strength at the elevated temperatures that could be present at these locations and therefore resists bending and warping in the stack.

The tables of EPA Method 1 will be used to locate the traverse points as required for the Method 20 O_2 traverse. It is expected that the size and configuration of the combined cycle exhaust stack will require that 44 traverse points be used for the initial O_2 traverse. Appendix F of this test plan has been reserved for stack diagrams and sample traverse point layout schemes .

K-type thermocouples and digital thermometer will be used to measure the stack temperature at each traverse point. This equipment will also be used to measure the stack temperature during all test runs.

The instrumental analysis procedures of EPA Method 3a will be used for determination of O_2 and CO_2 concentrations. The CO_2 analyzer that will be used is based on the principle of infrared absorption; and, the O_2 analyzer operates on a paramagnetic cell. Instrumental analyses will be used in lieu of an Orsat or a Fyrite procedure due to the greater accuracy and precision provided by the instruments.

A calculation technique contained in EPA Method 3b will be used to verify the measured concentrations of O_2 and CO_2. The F_o calculation of Method 3b will be performed using the measured O_2 and CO_2 concentrations and compared to the expected value published in EPA Method 3b.

EPA Method 10 will be used for measurement of CO concentrations. A continuous nondispersive infrared (NDIR) analyzer will be used for this analysis. This analyzer is equipped with a gas correlation filter which removes any interference from H_2O, CO_2, or other combustion products.

NOx and O_2 measurements (as required by Subpart GG) will be made using EPA Method 20. The NOx analyzer to be used operates on the principle of chemiluminescence and the O_2 analyzer uses a paramagnetic cell as a detection principle. As required, the NOx analyzer is equipped with an NO_2 to NO converter to allow for measurement of all forms of NOx as per EPA's definition. NOx mass emission rates will be calculated as if all the NOx were in the form of NO_2. This approach corresponds to EPA's convention, however, it tends to overestimate the actual NOx mass emission rates since the majority of NOx is in the form of NO which has less mass per unit volume (i.e. lbs. of emissions per ppmv concentration) than NO_2.

As required by Method 20, an initial O_2 traverse will be conducted on the unit while at low load. All subsequent tests will be conducted at the eight points of lowest O_2 concentration. Sampling at each traverse point will be conducted for a minimum of 1 minute plus the average sample system response time. The sample system response time will be conducted prior to testing (see *Quality Assurance Activities*); and, based on previous tests,-it is expected to be approximately 1 minute. Therefore, Cubix expects to sample for at least 2-minutes per point, making each test run a minimum of 16-minutes in duration (Cubix suggests 24 minute test runs).

Opacity Tests

During these compliance tests, visible emission tests will be performed by FPC certified personnel. To comply with 40 CFR 60.11, three one hour opacity readings will be made while firing turbine only. One 1-hour run will be made at full load, one 1-hour run will be made at the lowest load tested and a final run at an intermediate load. Likewise, while performing the joint firing tests, one 1-hour run will be performed at full load turbine and full fired duct burners. Two more 1-hour runs will be conducted at reduced loads of the duct burner as steam load will allow. Opacity observations shall be made using the procedures of EPA Method 9. FDEP certified personnel (via EPA procedures) shall be used for these opacity observations.

Exhaust Flow Measurements

The stoichiometric calculations of EPA Method 19 will be used to calculate a volumetric flow rate out the exhaust stack. This calculation requires knowledge of the F-factors and heating value of the fuel (as obtained from the fuel composition analysis), and the combustion air rate (as obtained from the diluent concentrations in the stack). Since fuel analyses will not be made until after testing, typical or published values will be used to calculate the volumetric flow rates in presentation of preliminary results. The final emission test report will use the calculated values for F-factors and heating values of each fuel (daily). This strategy will apply to all mass emission rate calculations including the duct burner emission calculations.

Unit Operation Documentation

To document the operational status of the unit during the tests as well as to allow Cubix to calculate stack flow rates, Florida Power Corp. will provide data for each test run. The data that will be recorded at 5-minute intervals, and includes:

1) Mean turbine exhaust temperature
2) Steam injection rate
3) Fuel flow
4) Steam/fuel ratio
5) Compressor inlet temperatures
6) Specific humidity
7) Inlet guide vane angle
8) Generator output (MW)
9) Compressor discharge pressure
10) Duct burner fuel flow
11) Stack temperature

Fuel Analyses

The natural gas analyses will consist of measurements of total sulfur and composition. The ASTM methods to be used for this fuel analyses are as follows:

ASTM D 3588 for Heating Value
ASTM D 3588 for Specific Gravity
ASTM D 3246 for Total Sulfur
ASTM D 1945 for Composition of Gas

One natural gas sample will be taken daily, and will be collected in Teflon® lined stainless steel sample "bombs". The total sulfur analyses of the fuel will be used in conjunction with the fuel flow data to indirectly calculate the total SOx (i.e. SO_2) mass emission rates.

Miscellaneous Measurements

Additional measurements to be made by Cubix during each test run include atmospheric pressure (via aneroid aircraft barometer), ambient temperature, and relative humidity as obtained from sling psychrometry (i.e. wet and dry ambient temperatures).

Table 2:
Test Matrix

Unit #	Load*	Duct Burner	Parameters	Runs	O2 Traverse
LM 6000	Low	off	NOx, ~~CO~~, O2, VE**	3	44 pt
LM 6000	Low Int.	off	NOx, ~~CO~~, O2, VE**	3	no
LM 6000	Int.	off	NOx, ~~CO~~, O2, VE**	3	no
LM 6000	Full	off	NOx, ~~CO~~, O2, VE**	3	no
LM 6000	Full***	100%***	NOx, CO, O2, VE**	3	no

? Using Ambient Curve

* Loads will be determined by FPC and will range from minimum load (for O_2 traverse) to full load. Full load depends on the inlet air temperature on the day of the compliance test.

** Three one hour VE runs will be conducted on the turbine only and on the joint firing of the turbine and duct burner (total of 6 one hour runs). One run will be at the lowest load, one run at an intermediate load and one at the highest load. See "Opacity Tests" on page 7 of this workplan.

*** This full load condition is dependent on how much steam flow can be dumped. Load for the CT and duct burners may have to be adjusted.

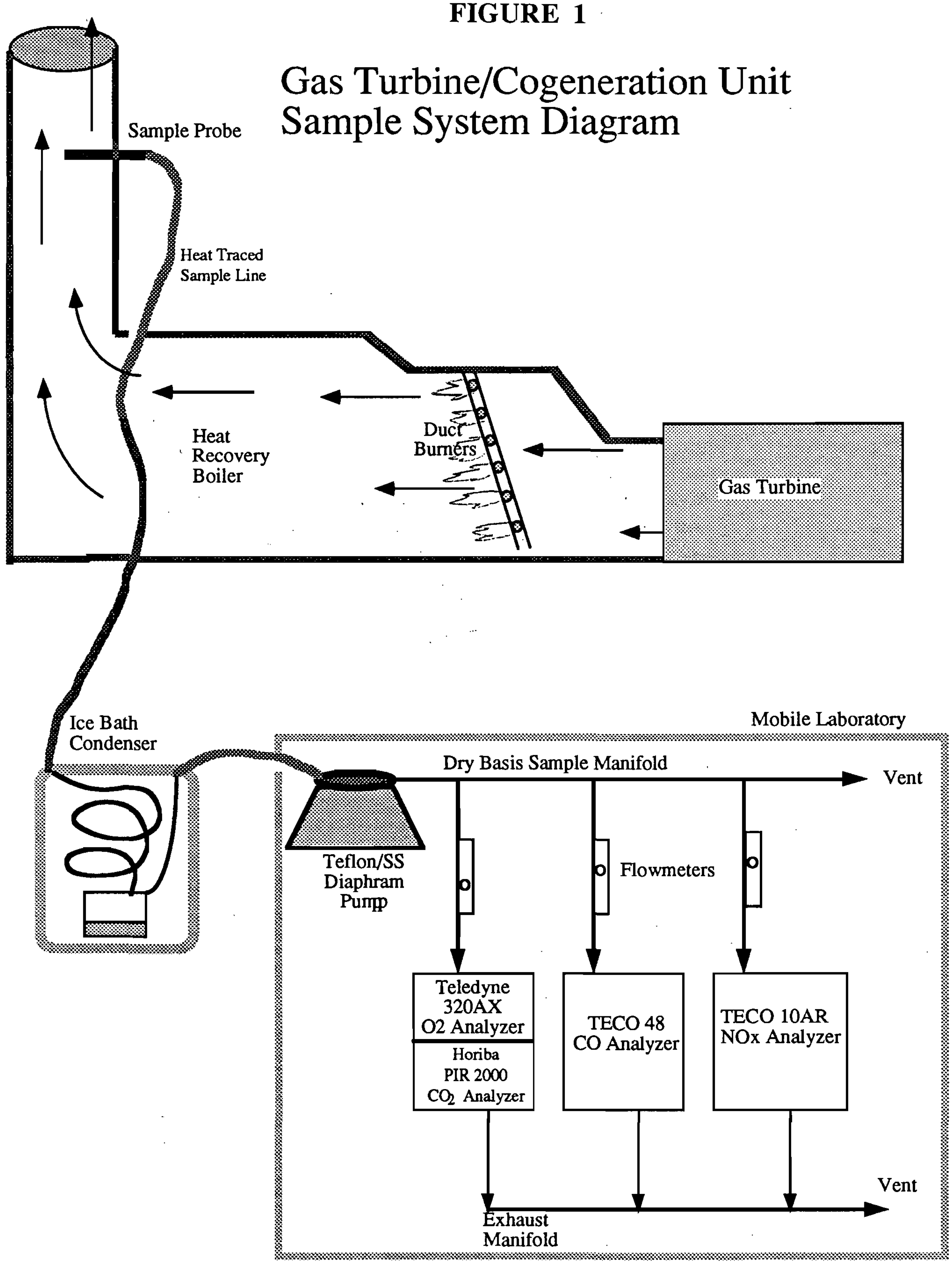
TABLE 3
ANALYTICAL INSTRUMENTATION

Analytical Instrumentation

Parameter	Model and Manufacturer	Common Use Ranges	Sensitivity	Response Time (sec.)	Detection Principle
NOx	TECO 10AR	0-10 ppm 0-100 ppm 0-200 ppm 0-500 ppm 0-1,000 ppm 0-5,000 ppm	0.1ppm	1.7	Thermal reduction of NO_2 to NO. Chemiluminescence of reaction of NO with O_3. Detection by PMT. Inherently linear for listed ranges.
CO	TECO 48	0-10 ppm 0-20 ppm 0-50 ppm 0-100 ppm 0-200 ppm 0-500 ppm 0-1000 ppm	0.1ppm	10	Infrared absorption, gas filter correlation detector, micro-processor based linearization
CO_2	Servomex 1410 B	0-4% 0-20%	0.02%	30	Infrared absorption, analog linearization.
O_2	Servomex 1420 B	0-10% 0-25 %	0.1%	15	Paramagnetic cell, inherently linear.

NOTE: Higher ranges available by sample dilution.
Other ranges available via signal attenuation.

FIGURE 1


Gas Turbine/Cogeneration Unit
Sample System Diagram
Sample Probe
Heat Traced
Sample Line
Heat
Recovery
Boiler
Duct
Burners
Gas Turbine
Ice Bath
Condenser
Mobile Laboratory
Dry Basis Sample Manifold
Vent
Teflon/SS
Diaphram
Pump
Flowmeters
Teledyne
320AX
O2 Analyzer
Horiba
PIR 2000
CO2 Analyzer
TECO 48
CO Analyzer
TECO 10AR
NOx Analyzer
Vent
Exhaust
Manifold

QUALITY ASSURANCE ACTIVITIES

A number of quality assurance activities will be undertaken prior to, following, and during this testing project. This section of the test plan combined with the example documentation in Appendices C and D describes each of those activities.

Each instrument's response will be checked and adjusted in the field prior to the collection of data via multi-point calibration. The instrument's linearity will be checked by first adjusting its zero and span responses to zero nitrogen and an upscale calibration gas in the range of the expected concentrations. The instrument response will then be challenged with at least one other calibration gas of known concentration. If the instrument's response does not agree with the calibration gases within ± 2 percent of range, corrective action will be taken prior to beginning the tests.

Each test run will be bracketed by a zero and span check. After each test run, a zero gas and a calibration gas in the range of the span value of the instrument will be introduced to each analyzer to determine the analyzer drift during the run. If the analyzer drifts more than 2% during a test run, that run will be repeated. Appendix C contains an example of a quality assurance worksheet that will be prepared by Cubix to summarize the multi-point linearity check and all zero and span checks.

Interference response tests on the instruments have been conducted by the instrument vendors and/or Cubix Corporation on the NOx, O_2, CO_2, and CO analyzers. The sum of the interference responses for the stipulated combustion products is less than 2 percent of the applicable full scale span value. The instruments to be used for the tests meet the performance specifications for EPA Methods 3a, 10, and 20. Results of these interference response tests are contained in Appendix C.

The residence time of the sampling and measurement system has been estimated using the pump flow rate and the sampling system volume. The pump's rated flow rate is 0.8 SCFM at 5 psig. The sampling system volume using a typical Cubix sample system has been calculated to be approximately 0.139 scf. Therefore, the minimum sample residence time is less than 11 seconds.

The NOx and O_2 sampling and analysis system will be checked for response time according to the procedures outlined in EPA Method 20. An example data sheet that presents the data from a previous response time check is included in Appendix C. During this check, the average NOx analyzer's response times were 53.6 seconds upscale and 49.9 seconds downscale. The O_2 analyzer's response times were 55.8 seconds upscale and 32.8 seconds downscale.

Each time the sampling system is set up, a leak check will be conducted prior to testing. The sampling system leak check will demonstrate that a vacuum greater than 10" Hg (probably >20 in Hg) can be held for at least 1 minute with a decline of less than 1" Hg. A leak test will also be conducted before a sample system is dismantled (i.e. after a test series) to ensure that no sample dilution occurred due to ambient air leakage during the tests.

The absence of leaks in the sampling system will also be verified by a sample system bias check. The sampling system's integrity will be tested by comparing the responses of each analyzer to calibration gases introduced via two paths. The first path will be delivered into the analyzer via the zero/span calibration manifold. The second path will consist of introducing a calibration gas into the sample system at the sample probe. Any difference in the instrument responses by these two methods is attributed to sampling system bias or leakage. The sample system bias checks will be conducted as frequently as the leak checks (i.e. after setting up a sample system and prior to dismantling a sample system). The sample system bias checks will demonstrate that no degradation of the sample occurs in the sample system due to absorption, leakage, or contamination.

The efficiency of the NO_2 to NO converter in the NOx analyzer will be checked by having the analyzer sample a mixture of NO in N_2 standard gas and zero air from a Tedlar® bag. When this bag is mixed and exposed to sunlight, the NO is oxidized to NO_2 over a 30 minute period. If the NOx instrument's converter is 100% efficient, then the NOx response will not decrease as the NO in the bag is converted to NO_2. The criterion for acceptability is a demonstrated NOx converter efficiency greater than 95%. Strip chart excerpts from previous NOx converter efficiency checks, as well as sample system bias checks, are provided in Appendix G. An example of an Instrumental Quality Assurance Worksheet which summarizes the results of these activities is also included in Appendix C.

The control gases used to calibrate the instruments will be analyzed and certified by the compressed gas vendors to ±1% accuracy. EPA Protocol No. 1 will be used for the NOx gases to assign the concentration values traceable to the National Institute of Standards and Technology (NIST), Standard Reference Materials (SRM's). Examples of calibration gas certifications for a typical turbine test are included in Appendix D.

TEST REPORT AND CALCULATIONS

Test Report

A formal test report documenting the results of the testing program will be prepared after the field testing. The contents of the report will include the following sections:

Introduction: This section will include background data for the tests (i.e. names, addresses, dates, units tested, parameters measured, etc...)

Summary of Results: This section will include tabular summaries of the mass emission rates for NOx (ppmvd, ppmvd at 15% O_2, lbs/MMBtu, and lbs/hr), CO (ppmvd, lbs/MMBtu, and lbs/hr), SO2 (lbs/hr) and recorded visible emission results. During the joint fire tests, the duct burner contribution of NOx and CO emissions will be reported in terms of lbs/MMBtu. The permit limits will also be reported for each applicable parameter.

Each tabular summary will also include sections for operational data, fuel data, and ambient conditions. The stack volumetric flow rate as determined from both O_2 and CO_2 based F-factors will also be included. The mass emission rates will be calculated from the stack flow rate determined by the O_2 F-factor. The times and dates of each test run will be noted at the head of each column in the tabular summary. The joint fire tests will be reported separately from the turbine only tests. Appendix A of this test plan is reserved for examples of the tabular summaries for both the turbine and joint-fired tests.

Preceding the tabular summaries, *Summary of Results* will include text that provides any necessary commentary or explanation of the test results.

Process Description: A brief description of the units tested is provided in this section of the report. Included will be rated operating conditions and stack configuration descriptions. Any applicable model and serial numbers of the unit will also be included.

Analytical Techniques: This section of the report describes the test methods and procedures that were used. This section will closely resemble the *Test Measurements* section of this test plan.

Quality Assurance Activities: Closely matching the section of this test plan of the same title, this portion of the test report will describe the many QA activities conducted during the tests. The text of this section will be supported by the documents included in the Quality Assurance and Calibration Certifications sections of the Appendix.

Appendices: The supporting documentation will be divided into the following sections:

Appendix A: Field Data Sheets: Stack diagrams, sign-in sheets, templates, preliminary water injection tests, etc...

Appendix B: Example Calculations: Examples of all formulas used for presentation of results in *Summary of Results.*

Appendix C: Fuel Data: Results of all fuel analyses and Cubix's F-factor and heating value calculation templates.

Appendix D: Operational Data: Computer print-outs supplied by the operator which document the operational status of each unit during each test run. Cubix will mark the test run designations and times of each test run on these print-outs and provide the average operational parameters for each run.

Appendix E: Quality Assurance Activities: Documentation of the various QA Activities conducted for the tests including system response time tests, NOx converter efficiency check strip chart and data sheet, sample system bias checks strip charts and data sheets, interference response checks, etc...

Appendix F: Calibration Certifications: Calibration data for calibration gases, thermometers, altimeter, etc...

Appendix G. Strip Chart Records: Copies of all strip chart recordings made during the tests (if desired).

Appendix H. Opacity Observations: Copies of all opacity field data sheets

Calculations

Emission calculations will be performed by customized spread sheet programs installed on a Macintosh computer. Appendix A of this test plan provides examples of the computer spread sheets Cubix will build for this project. Appendix B shows example calculations of mass emission rates from a turbine only test run and a joint fired test run.

APPENDIX A: EXAMPLE TABLES AND SPREADSHEETS

Example of Natural Gas Fired Test Template

XXXXXXXX												
XXXXX												
Solar Taurus Turbine W HRSG												
Date												
Turbine #	TCP-2	TCP-2	TCP-2	TCP-2	TCP-2	TCP-2	TCP-2	TCP-2	TCP-2	TCP-2	TCP-2	TCP-2
Test Number	C-16	C-17	C-18	C-19	C-20	C-21	C-22	C-23	C-24	C-25	C-26	C-27
Start Time	847	935	1015	1117	1201	1244	1329	1413	1455	1538	1620	1706
Stop Time	923	1007	1048	1149	1233	1316	1401	1445	1527	1610	1652	1738
Turbine Operational Data												
Power (KW)	2690	2675	2672	3407	3411	3413	3090	3098	3102	2900	2924	2920
Power Turbine Speed (%x14951=rpm)	100	100	100	100	100	100	100	100	100	100	100	100
T-5 Combustor Temp. (°F)	1207	1203	1202	1400	1400	1400	1400	1330	1329	1283	1284	1281
T-1 Air Inlet Temp. (°F)	62.7	62.7	63.0	69.1	69.5	69.3	69.4	69.7	70.1	70.1	69.0	67.8
Compressor Discharge (psig)	116.0	116.5	116.0	122.0	122.0	122.0	118.0	118.0	118.0	116.0	116.0	116.0
Fuel Flow (SCFM)	712	708	705	844	846	843	790	788	794	753	757	751.3
Fuel Flow (SCFH)	42720	42480	42300	50640	50760	50580	47400	47280	47640	45180	45420	45078
Heat Input (MMBtu/hr)	4.40E+07	4.38E+07	4.36E+07	5.22E+07	5.23E+07	5.21E+07	4.89E+07	4.87E+07	4.91E+07	4.66E+07	4.68E+07	4.65E+07
H2O Flow (gal/min)	1.800	1.800	1.800	2.720	2.700	2.630	2.600	2.230	2.260	2.020	2.040	2.020
H2O-to-fuel Ratio (lb/lb)	0.457	0.457	0.460	0.567	0.570	0.569	0.523	0.521	0.522	0.495	0.495	0.490
Fuel Specific Gravity	0.591	0.591	0.591	0.591	0.591	0.591	0.591	0.591	0.591	0.591	0.591	0.591
Fuel Heating Value (Btu/SCF)	1031	1031	1031	1031	1031	1031	1031	1031	1031	1031	1031	1031
Turbine Sensor Relative Hum. (%)	56.1	56.3	55.8	54.9	52.07	49.4	48.8	48.3	47.6	46.5	45.8	45.9
Turbine Sensor Pbar (in. Hg)	26.4	26.4	26.4	26.5	26.5	26.5	26.4	26.4	26.4	26.4	26.4	26.4
Steam Flow (KPH)	15.63	16.41	16.28	21.11	22.09	20.28	17.79	17.75	17.53	16.8	16.8	16.83
Ambient Conditions												
Barometer (in. Hg)	26.22	26.22	26.22	26.25	26.25	26.25	26.25	26.25	26.15	26.15	26.15	26.15
Temperature (°F dry)	85	85	87	94	96	99	101	102	103	101	107	104
Temperature (°F wet)	60	60	61	67	66	67	68	76	69	68	69	68
Humidity (lbs/lb of air)	0.0066	0.0066	0.0068	0.0096	0.0083	0.0084	0.0087	0.0154	0.0091	0.0088	0.0082	0.0081
Measured Emissions												
NOx (ppmv)	23.4	24.0	24.0	26.0	25.0	26.0	26.0	26.0	25.0	25.0	25.0	23.6
NOx (ppm @ 15% O2)	**32.3**	**33.3**	**33.2**	**28.4**	**27.3**	**28.4**	**30.7**	**31.0**	**29.8**	**31.7**	**31.7**	**29.9**
CO (ppmv)	36.5	39.0	38.0	7.0	7.0	6.5	11.0	12.0	12.0	17.0	17.0	20.0
CO (ppmv @15% O2)	**50.4**	**54.1**	**52.5**	**7.6**	**7.6**	**7.1**	**13.0**	**14.3**	**14.3**	**21.6**	**21.6**	**25.4**
O2 (%)	16.63	16.65	16.63	15.50	15.50	15.50	15.90	15.95	15.95	16.25	16.25	16.25
CO2 (%)	2.40	2.40	2.50	3.10	3.10	3.10	2.84	2.80	2.80	2.76	2.80	2.76
Stack Flow Rates (SCFH)												
O2 Stoichiometry	1.87E+06	1.86E+06	1.85E+06	1.75E+06	1.75E+06	1.75E+06	1.77E+06	1.78E+06	1.79E+06	1.81E+06	1.82E+06	1.81E+06
Fuel Fo Factor	1.78	1.77	1.71	1.74	1.74	1.74	1.76	1.77	1.77	1.68	1.66	1.68
Mass Emissions - "F" factor												
NOx (lbs/hr)	5.21	5.34	5.29	5.43	5.23	5.42	5.49	5.53	5.36	5.41	5.44	5.09
CO (lbs/hr)	4.94	5.28	5.10	0.89	0.89	0.82	1.41	1.55	1.56	2.24	2.25	2.62

Testing by Cubix Corporation, Austin, Texas

Example Turbine Template

	A	B	C	D
1	XXXXXXXXX			
2	XXXXXX Cogen Facility			
3	GE Frame 7			
4				
5	Date			
6	Test Series	GTO-3	GTO-3	GTO-3
7	Fuel Type	NG	NG	NG
8	**Test Number**	**C-9**	**C-10**	**C-11**
9	Start Time	1020	1240	1329
10	Stop Time	1221	1315	1401
11	**Turbine Operation**			
12	Power (MW)	79.5	78.50	78.5
13	Power Turbine Speed (rpm)	3600	3600	3600
14	Exhaust Temp. (TTXC-°F)	993	994	994
15	Compressor Discharge (psig)	159	159	159
16	Inlet Guide Vanes (degrees)	82	82	82
17	Fuel Flow (lbs/sec)	10.476	10.375	10.422
18	Steam Flow (lbs/sec)	9.677	9.670	9.654
19	Fuel Specific Gravity	0.604	0.604	0.604
20	Fuel Heating Value (Btu/SCF or Btu/lb)	1033	1033	1033
21	Fuel Flow (SCF/hr)	830095	822092	825816
22	**Ambient Conditions**			
23	Barometer (in. Hg)	27.91	27.91	27.91
24	Temperature (°F dry)	49	60	63
25	Temperature (°F wet)	43	59	59
26	Humidity (lbs/lb of air)	0.0048	0.0110	0.0103
27	**Measured Emissions**			
28	NOx (ppmv)	37.5	37	37.0
29	NOx (ppm @ 15% O2)	37.5	37.0	37.4
30	CO (ppmv)	0.7	0.6	0.6
31	O2 (%)	15.00	15.00	15.06
32	CO2 (%)	3.45	3.45	3.45
33	**Stack Flow Rates (SCFH)**			
34	O2 Stoichiometry	2.63E+07	2.61E+07	2.65E+07
35	Pitot Tube-Stack	2.63E+07	2.64E+07	2.58E+07
36	**Mass Emissions (O2 Stoich)**			
37	NOx (lbs/hr)	117.86	115.17	116.88
38	CO (lbs/hr)	1.34	1.14	1.15
39	**Mass Emissions (Pitot-Stack)**			
40	NOx (lbs/hr)	117.95	116.43	114.02
41	CO (lbs/hr)	1.34	1.15	1.12

Example Joint Fire Turbine Template

	A	B	C	D
1	XXXXXXX			
2	XXXXXX			
3	Solar Taurus Turbines W HRSG			
4				
5	Date			
6	Turbine #	TCP-3	TCP-3	TCP-3
7	Test Number	C-13	C-14	C-15
8	Start Time	1412	1530	1650
9	Stop Time	1510	1620	1740
10	Turbine Operation - From Solar Instrumentation			
11	Power (KW)	3472	3475	3465
12	Power Turbine Speed (%x14951=rpm)	100	100	100
13	T-5 Combustor Temp. (°F)	1400	1400	1400
14	T-1 Air Inlet Temp. (°F)	65.2	64.6	63.9
15	Compressor Discharge (psig)	124	124	124
16	H2O Flow (gal/min)	2.74	2.70	2.70
17	H2O-to-fuel Ratio (lb/lb)	0.592	0.586	0.599
18	Turbine Sensor Relative Hum. (%)	74.9	70.2	67.4
19	Turbine Sensor Pbar (in. Hg)	26.4	26.3	26.3
20	Ambient Conditions - Collected by Cubix			
21	Barometer (in. Hg)	26.10	26.05	26.05
22	Temperature (°F dry)	98	100	101
23	Temperature (°F wet)	79	81	82
24	Humidity (lbs/lb of air)	0.0194	0.0211	0.0219
25	Fuel Flow Data			
26	Turbine NG Fuel Flow (SCFM)	839.4	840.0	841.3
27	Turbine NG Fuel Flow (SCFH)	50364	50400	50478
28	Turbine NG Fuel Flow (MMBtu/Hr)	51.9	52.0	52.0
29	Fuel Heating Value (Btu/SCF)	1031	1031	1031
30	Fuel Specific Gravity	0.591	0.591	0.591
31	Fuel O2 "F" Factor (DSCF/MMBtu)	8652	8652	8652
32	Duct Burner Fuel Flow (SCFM)	164.4	166.0	165.3
33	Duct Burner Fuel Flow (SCFH)	9864	9960	9918
34	Duct Burner Firing Rate (MMBtu/Hr)	10.2	10.3	10.2
35	Turbine Only Measured Emissions			
36	NOx (ppmv)	28.0	28.0	29.0
37	**NOx (ppm @ 15% O2)**	**30.6**	**30.6**	**31.7**
38	CO (ppmv)	4.0	5.0	5.0
39	**CO (ppmv @15% O2)**	**4.4**	**5.5**	**5.5**
40	O2 (%)	15.50	15.50	15.50
41	CO2 (%)	3.10	3.06	3.04
42	continued on next page			
43	Test Number	**C-13**	**C-14**	**C-15**
44	Turbine Only Flow Rates (SCFH)			
45	O2 Stoichiometry	1.74E+06	1.74E+06	1.74E+06
46	Fuel Fo Factor	1.74	1.76	1.78
47	Turbine Only Mass Emissions - "F" factor			
48	NOx (lbs/hr)	5.81	5.82	6.03
49	NOx (lb/MMBtu)	0.11	0.11	0.12
50	CO (lbs/hr)	0.50	0.63	0.63
51	CO (lbs/MMBtu)	0.01	0.01	0.01
52	Joint Fired Measured Emissions			
53	NOx (ppmv)	32.0	32.0	33.0
54	**NOx (ppmv @ 15% O2)**	**28.2**	**28.4**	**29.3**
55	CO (ppmv)	6.0	7.0	7.0
56	**CO (ppmv @ 15% O2)**	**5.3**	**6.2**	**6.2**
57	O2 (%)	14.20	14.25	14.25
58	CO2 (%)	3.80	3.70	3.72
59	Joint Fire Flow Rates (SCFH)			
60	O2 Stoichiometry	1.68E+06	1.69E+06	1.69E+06
61	Pitot Tube Flow	1.75E+06	1.82E+06	1.77E+06
62	Joint Fired Mass Emissions - "F" factor			
63	NOx (lbs/hr)	6.40	6.47	6.67
64	NOx (lb/MMBtu)	0.63	0.63	0.65
65	CO (lbs/hr)	0.73	0.86	0.86
66	CO (lbs/MMBtu)	0.07	0.08	0.08
67	Joint Fired Mass Emissions - Pitot			
68	**NOx (lbs/hr)**	**6.67**	**6.97**	**6.98**
69	NOx (lb/MMBtu)	0.66	0.68	0.68
70	**CO (lbs/hr)**	**0.76**	**0.93**	**0.90**
71	CO (lbs/MMBtu)	0.07	0.09	0.09
72	Duct Burner Contribution			
73	NOx (lbs/hr)	0.59	0.65	0.64
74	**NOx (lb/MMBtu)**	**0.06**	**0.06**	**0.06**
75	CO (lbs/hr)	0.23	0.23	0.23
76	**CO (lbs/MMBtu)**	**0.02**	**0.02**	**0.02**
77	Method 19			
78	NOx (lb/MMBtu)	0.06	0.07	0.07
79	CO (lbs/MMBtu)	0.02	0.02	0.02

Example Joint Fired Template

	A	B	C	D
1	**XXXXXXXX**			
2	GTO3 Joint Firing Tests			
3	Date			
4	**Test Number**	**C-12**	**C-13**	**C-14**
5	Start Time	1738	1838	1926
6	Stop Time	1830	1918	1956
7	**Unit Operation**			
8	Power (MW)	76.9	76.5	76.5
9	Average Turbine Exhaust Temperature (°F)	997	996	997
10	Steam Injection (lbs/sec.)	8.990	9.047	9.055
11	Steam/Fuel Ratio (lb/lb)	0.88	0.88	0.88
12	**Turbine NG Fuel Flow (lbs/sec)**	10.244	10.251	10.233
13	Turbine Fuel Flow (MMBtu/hr)	822.50	823.06	821.62
14	Fuel Heating Value (Btu/lb)	22303	22303	22303
15	Fuel O2 F Factor	8666	8666	8666
16	Fuel CO2 F Factor	1032	1032	1032
17	**HRSG Duct Burner Fuel Flow (lb/hr)**	5928	5928.0	5928.0
18	Fuel Heating Value (Btu/lb)	21746	21746	21746
19	Fuel O2 F Factor	8666	8666	8666
20	Fuel CO2 F Factor	1032	1032	1032
21	Duct Burner Firing Rate (MMBtu/hr)	129	129	129
22	**Ambient Conditions**			
23	Barometer (in. Hg)	27.91	27.91	27.91
24	Temperature (°F dry)	63	64	61
25	Temperature (°F wet)	60	61	59
26	Humidity (lbs/lb of air)	0.0110	0.0114	0.0108
27	**Turbine Measured Emissions (dry basis)**			
28	NOx (ppmv)	40.4	40.0	41.1
29	NOx (ppmv @ 15% O2)	40.4	40.0	41.1
30	CO (ppmv)	0.6	0.6	0.6
31	O2 (%)	15.00	15.00	15.00
32	CO2 (%)	3.53	3.51	3.52
33	**Turbine Duct Flow Rates (DSCFH)**			
34	EPA Fo Factor	1.67	1.68	1.68
35	O2 Stoichiometry	2.52E+07	2.53E+07	2.52E+07
36	CO2 Stoichiometry	2.40E+07	2.42E+07	2.41E+07
37	**Turbine Mass Emissions (O2 F Fact.)**			
38	NOx (lbs/hr)	121.80	120.67	123.77
39	NOx (lbs/MMBtu)	0.15	0.15	0.15
40	CO (lbs/hr)	1.10	1.10	1.10
41	CO (lbs/MMBtu)	0.0013	0.0013	0.0013
42	**Turbine Mass Emissions (CO2 F Fact.)**			
43	NOx (lbs/hr)	115.99	115.58	118.21
44	**Joint Fire Measured Emissions (dry basis)**			
45	NOx (ppmv)	41.5	41.3	42
46	CO (ppmv)	3.6	2.9	3.5
47	O2 (%)	13.50	13.7	13.86
48	CO2 (%)	4.28	4.31	4.21
49	**Joint Fire Stack Flow Rates (DSCFH)**			
50	EPA Fo Factor	1.73	1.67	1.67
51	O2 Stoichiometry	2.33E+07	2.39E+07	2.45E+07
52	CO2 Stoichiometry	2.29E+07	2.28E+07	2.33E+07
53	**Joint Fire Mass Emissions (O2 F Fact.)**			
54	NOx (lbs/hr)	115.39	118.09	122.63
55	NOx (lbs/MMBtu)	0.12	0.12	0.13
56	CO (lbs/hr)	6.09	5.04	6.21
57	CO (lbs/MMBtu)	0.006	0.005	0.007
58	**Joint Fire Mass Emissions (CO2 F Fact.)**			
59	NOx (lbs/hr)	113.67	112.40	116.85
60	***Duct Burner Contribution (O2 F Fact.)***			
61	NOx (lbs/hr) via O2 F Factor	-6.41	-2.58	-1.14
62	NOx (lbs/hr) via CO2 F Factor	-2.32	-3.17	-1.36
63	**NOx (lbs/MMBtu O2 F factor)**	**-0.050**	**-0.020**	**-0.009**
64	**NOx (lbs/MMBtu CO2 F factor)**	**-0.018**	**-0.025**	**-0.011**
65	CO (lbs/hr)	4.99	3.94	5.12
66	CO (lbs/MMBtu)	0.039	0.031	0.040
67	**Method 19**			
68	NOx (lbs/MMBtu)	-0.050	-0.020	-0.009
69	CO (lbs/MMBtu)	0.039	0.031	0.040

O2 F Factor Calculation : Example - Natural Gas

Client: XXXXXXXXXX
Sample ID: Natural gas fired turbine
Time: XXXXX
Date: XXXXXX

CALCULATION OF DENSITY AND HEATING VALUE

Componen	% Volume	Molecular Wt.	Density (lb/ft3)	% volume x Density	weight %	Component Gross Btu/lb	Weight Fract. Btu	Gross Heating Value (Btu/SCF)	Volume Fract. Btu
Hydrogen	0.0000	2.016	0.0053	0.00000	0.0000	61100	0.00	325	0
Oxygen	0.0000	32.000	0.0846	0.00000	0.0000	0	0.00	0	
Nitrogen	1.7400	28.016	0.0744	0.00129	2.8623	0	0.00	0	0
CO2	0.4700	44.01	0.117	0.00055	1.2158	0	0.00	0	0
CO	0.0000	28.01	0.074	0.00000	0.0000	4347	0.00	322	0
Methane	93.9100	16.041	0.0424	0.03982	88.0370	23879	21022.35	1013	951.308
Ethane	3.0900	30.067	0.0803	0.00248	5.4861	22320	1224.49	1792	55.3728
Ethylene	0.0000	28.051	0.0746	0.00000	0.0000	21644	0.00	1614	0
Propane	0.5500	44.092	0.1196	0.00066	1.4544	21661	315.04	2590	14.245
propylene	0.0000	42.077	0.111	0.00000	0.0000	21041	0.00	2336	0
Isobutane	0.0600	58.118	0.1582	0.00009	0.2099	21308	44.72	3363	2.0178
n-butane	0.0900	58.118	0.1582	0.00014	0.3148	21257	66.92	4016	3.6144
Isobutene	0.0000	56.102	0.148	0.00000	0.0000	20840	0.00	3068	0
Isopentane	0.0200	72.144	0.1904	0.00004	0.0842	21091	17.76	4008	0.8016
n-pentane	0.0200	72.144	0.1904	0.00004	0.0842	21052	17.72	3993	0.7986
n-hexane	0.0500	86.169	0.2274	0.00011	0.2514	20940	52.64	4762	2.381
H2S		34.076	0.0911	0.00000	0.0000	7100	0.00	647	0
total	100.00		Average Density	0.04523	100.0000	Gross Heating Value		Gross Heating Value	
			Specific Gravity	0.59122		Btu/lb	22762	Btu/SCF	1031

CALCULATION OF F FACTORS

Componen	Mol. Wt.	C Factor	H Factor	% volume	Fract. Wt.	Weight Percents: Carbon	Hydrogen	Nitrogen	Oxygen
Hydrogen	2.016	0	1	0.00	0.0000	0	0		
Oxygen	32	0	0	0.00	0.0000				0
Nitrogen	28.016	0	0	1.74	48.7478	0	0	2.85257	
CO2	44.01	0.272273	0	0.47	20.6847	0.32955963	0		0.87996
CO	28.01	0.42587	0	0.00	0.0000	0	0		0
Methane	16.041	0.75	0.25	93.91	1506.4103	66.1126772	22.037559		
Ethane	30.067	0.8	0.2	3.09	92.9070	4.349294	1.0873235		
Ethylene	28.051	0.85714	0.14286	0.00	0.0000	0	0		
Propane	44.092	0.81818	0.18182	0.55	24.2506	1.16105167	0.2580118		
Propene	42.077	0.85714	0.14286	0.00	0.0000	0	0		
Isobutane	58.118	0.82759	0.17247	0.06	3.4871	0.16887188	0.035193		
n-butane	58.118	0.82759	0.17247	0.09	5.2306	0.25330782	0.0527894		
Isobutene	56.102	0.85714	0.14286	0.00	0.0000	0	0		
Isopentane	72.144	0.83333	0.16667	0.02	1.4429	0.07036026	0.0140724		
n-pentane	72.144	0.83333	0.16667	0.02	1.4429	0.07036026	0.0140724		
n-hexane	86.169	0.83721	0.16279	0.05	4.3085	0.21107445	0.041042		
H2S	34.08	0	0	0.00	0.0000	0	0		
Totals				100.00	1708.9124	72.7265572	23.54	2.85257	0.87996

CALCULATED VALUES		
O2 F Factor (dry)	**8653**	DSCF of Exhaust/MM Btu of Fuel Burned @ 0% excess air
O2 F Factor (wet)	**10649**	SCF of Exhaust/MM Btu of Fuel Burned @ 0% excess air
Moisture F Factor	**1996**	SCF of Water/MM Btu of Fuel Burned @ 0% excess air
Combust. Moisture	**18.7**	volume % water in flue gas @ 0% excess air
CO2 F Factor	**1026**	DSCF of CO2/MM Btu of Fuel Burned @ 0% excess air

APPENDIX B:
EXAMPLE CALCULATIONS

Turbine Exhaust
Concentration Standards
(40CFR60 Subpart GG and Appendix A, Method 20)

Date:	XXXXX
Plant:	XXXXXXXX Corporation
Stack:	Solar Taurus Turbine TCP-3
Technician:	RK, TS, LI

Calculate NO_x Emission Concentration Standard

For turbines having fuel flows at peak load between 10 and 100 MMBtu/hr:

$$\text{ppmv } NO_x \text{ Standard} = \left\{150 \times \left(\frac{13658\left(\frac{\text{Btu}}{\text{Kw-hr}}\right)}{Y}\right) + F\right\}$$

where:

Y = Measured or manufacturer's rated efficiency in terms of lower heating value of fuel in $\left(\frac{\text{Btu}}{\text{Kw-hr}}\right)$ at actual peak load. (10,180 Btu/Hp-hr = 14.4 Kilojoules/Watt-hr = 13,658 Btu/Kw-hr). "Y" can not be greater than these values.

F = Adjustment to NO_x concentration standard (ppm) according to fuel bound nitrogen content (excluding gaseous N_2).

Y (actual value) = 13284 $\left(\frac{\text{Btu}}{\text{Kw-hr}}\right)$ based on Run C-8 at full load.

$$\text{ppmv } NO_x \text{ Standard} = \left\{150 \times \left(\frac{13658\left(\frac{\text{Btu}}{\text{Kw-hr}}\right)}{13284\left(\frac{\text{Btu}}{\text{Kw-hr}}\right)}\right) + 0\right\} = \mathbf{154.2 \text{ ppmv}}$$

NO_x Adjustment to 15% O_2 and NO_x (EPA Corrected)

Date:	XXXXX	
Plant:	XXXXXXXXX	
Stack:	Solar Taurus Turbine TCP-3	
Technician:	RK, TS, LI	
Example Test Run:	C-13	
Measured Concentrations:	NO_x (ppmv)	28.0
	O_2 (%)	15.5

Calculation to Adjust NO_x to 15% O_2

$$NO_x \text{ @ } 15\%\ O_2 = NO_x \text{ measured (ppmv)} \times \left(\frac{5.9}{20.9 - O_2\% \text{ measured}}\right)$$

$$= 28.0 \times \left(\frac{5.9}{20.9 - 15.5\%}\right) = \mathbf{30.6 \text{ ppmv @ } 15\%\ O_2}$$

O_2 Based F Factor Emission Calculations for Natural Gas

Date:	XXXXX
Plant:	XXXXXXXXXXX
Stack:	Solar Taurus Turbine TCP-3
Technician:	RK, TS, SB
Example Test Run:	C-13

Measured Concentrations:	NO_x (ppmv)	28.0
	O_2 (%)	15.5

Fuel Flow = 50364 $\left(\frac{SCF}{hr}\right)$

Gross Heating Value = 1031 $\left(\frac{Btu}{SCF}\right)$

F_1 Factor = 8652 $\left(\frac{DSCF}{MMBtu}\right)$

Heat Flow Rate Calculation

$$Z_1\left(\frac{MMBtu}{hr}\right) = \text{Fuel Flow}\left(\frac{SCF}{hr}\right) \times \text{Gross Heating Value}\left(\frac{Btu}{SCF}\right) \times 10^{-6}$$

$$= 50364\left(\frac{SCF}{hr}\right) \times 1031\left(\frac{Btu}{SCF}\right) \times 10^{-6}$$

$$\mathbf{= 51.96}\ \left(\frac{\mathbf{MMBtu}}{\mathbf{hr}}\right)$$

Stack Gas Flow Calculation

$$Q_d\left(\frac{DSCF}{hr}\right) = \left\{\frac{Z_1 \times F_1 \times 20.9}{20.9 - O_2\%}\right\} = \left\{\frac{52.98\left(\frac{MMBtu}{hr}\right) \times 8652\left(\frac{DSCF}{MMBtu}\right) \times 20.9}{20.9 - 15.50\%}\right\}$$

$$\mathbf{= 1{,}738{,}793}\ \left(\frac{\mathbf{DSCF}}{\mathbf{hr}}\right)$$

Emissions in $\left(\frac{lbs}{hr}\right)$ Calculation via O_2 Stoichiometry

$$\left(\frac{lbs}{hr}\right) = \left\{ \text{Conc. (ppmv)} \times 10^{-6} \times \text{M.W.} \left(\frac{lbs}{lb\bullet mole}\right) \times 385.15^{-1} \left(\frac{lb\bullet mole}{DSCF}\right) \times Q_d \left(\frac{DSCF}{hr}\right) \right\}$$

$$NOx \left(\frac{lbs}{hr}\right) = \left\{ 28.0 \text{ ppmv} \times 10^{-6} \times 46 \left(\frac{lbs}{lb\bullet mole}\right) \times 385.15^{-1} \left(\frac{lb\bullet mole}{DSCF}\right) \times 1.74 \times 10^{6} \left(\frac{DSCF}{hr}\right) \right\}$$

$$= \mathbf{5.81} \left(\frac{\mathbf{lbs}}{\mathbf{hr}}\right)$$

Duct Burner contribution to Emissions

Refers to Test Run C-13

Ebo = Duct Burner contribution (lb/MMBtu)
Qft = fuel flow to turbine = 50,364 SCF/hr
BTUt = heating value of turbine fuel = 1031 BTU/SCF
Hg = heat input to turbine = Qft x BTUt = 51.9 MMBTU/h
Qfb = fuel flow to boiler = 9864 SCF/hr
BTUb = heating value of boiler fuel = 1031 BTU/SCF
Hb = heat input to boiler = Qfb x BTUb = 10.2 MMBTU/hr
Eg = pollutant rate from turbine = 5.81 lbs/hr = 0.11 lbs/MMBTU
Eco = pollutant rate from joint fire =6.4 lbs/hr= .63 lbs/MMBTU

Ebo = (Eco - Eg)/Hb

= (6.4 lb/hr - 5.81 lb/hr)/10.2 MMBtu/hr
= .058 lbs/MMBTU of NOx

*CO emissions calculated using same formula with appropriate CO emissions.

Calculations for Gaseous Emissions QA

Certified Gas Input

Concentration (% or ppmv) = concentration of gas from vendor certification

$$\text{Target (\% Chart)} = \left\{\left(\frac{\text{Concentration} \times 100}{\text{Full Scale}}\right) + \text{zero offset}\right\}$$

$$\text{For 160.9 ppmv } NO_X\text{, Target (\% Chart)} = \left\{\left(\frac{160.9 \times 100}{200}\right) + 2.0\right\} = 82.45$$

Initial Calibration and Linearity Check

Initial (% chart) = observed reading when calibration gas is analyzed

Difference (% chart) = Initial (% chart) – Target (% chart)

For 160.9 NO_X, Difference (% chart) = 83.00 – 82.45 = 0.55

Test Run C-1

$$\text{Average ppmv calculated from strip chart} = (\text{observed} - \text{zero offset}) \times \left\{\frac{\text{Full Scale}}{100}\right\}$$

$$= (14.0 - 2) \times \left\{\frac{200}{100}\right\} = \mathbf{24.0\ ppmv}$$

Calibration Check Run 403.8 ppmv NO_X C-1

Drift (% chart) = Final (% chart) – Target (% chart)

= 83.0 (% chart) – 82.45 (% chart) = 0.55 (% chart)

*The drift is considered to be acceptable within 2% of chart.

APPENDIX C: EXAMPLE QUALITY ASSURANCE ACTIVITIES

Instrumental Analysis
Quality Assurance Data

Date: [redacted]
Plant: [redacted]
Technician: TS

NOx Analyzer: NO2 to NO Converter Efficiency Test

	NOx Concentration (ppm)	% Decrease from Initial Concentration	NO Concentration (ppm)
Initial Concentration	85.0	0.0	66.0
10 minute Concentration	85.6	-0.3	61.0
20 minute Concentration	86.0	-0.2	59.0
30 minute Concentration	86.4	-0.2	56.0

Full Scale: 200

Sample System Bias Check

Parameter	Calibration Gas Concentration (ppm)	Full Scale Span (ppm)	Direct Calibration Response (ppm)	Sample System Response (ppm)	Sample System Bias (% of Span)
NOx	160.9	200	161.0	162.2	0.65
NOx	160.9	200	161.0	161.4	0.25
NOx	160.9	200	160.2	160.8	-0.05
NOx	160.9	200	161.4	161.0	0.05
NOx	160.9	200	161.0	161.2	0.15
NOx	160.9	200	161.6	162.0	0.55

Sample System Leak Check

Run #	in. of mercury (Intial)	in. of mercury (Final)
multipoint	21.0	21.0
C-3	20.0	20.0
C-6	21.0	21.0
C-7	20.5	20.5
C-9	21.5	21.5
C-16	20.5	20.5
C-19	22.0	22.0
C-28	21.0	21.0
C-30 (S.S. A)	21.0	21.0
C-30 (S.S. B)	22.0	22.0

Quality Assurance Worksheet: [redacted]

	CERTIFIED GAS INPUT		INITIAL CALIBRATION & LINEARITY CHECK		TEST RUN C-1	ZERO and SPAN CALIBRATION CHECK		TEST RUN C-2	ZERO and SPAN CALIBRATION CHECK	
	Concentration (% or ppm)	Target (% Chart)	Initial (% Chart)	Difference (% Chart)		Final (% Chart)	Drift (% Chart)		Final (% Chart)	Drift (% Chart)
NOx					Avg. ppm			Avg. ppm		
zero	0.00	2.0	2.0	0.0	24.0	2.0	0.0	25.0	2.0	0.0
low	19.70	11.9	11.5	-0.4	% Chart			% Chart		
mid	41.13	22.6	22.0	-0.6	14.0			14.5		
high	160.90	82.5	83.0	0.5		82.8	0.3		83.0	0.5
full scale	200.00				200.0			200.0		
O2					Avg.%			Avg.%		
zero	0.00	10.0	10.0	0.0	16.63	10.0	0.0	16.63	10.0	0.0
low	4.03	26.1	25.2	-0.9	% Chart			% Chart		
mid	7.90	41.6	42.0	0.4						
high	18.10	82.4	82.6	0.2	76.5	82.4	0.0	76.5	82.2	-0.2
full scale	25.00				25.0			25.0		
CO					Avg. ppm			Avg. ppm		
zero	0.00	5.0	5.0	0.0	47.0	5.0	0.0	44.0	5.0	0.0
low	40.17	13.0	12.8	-0.2						
mid	79.71	20.9	20.0	-0.9	% Chart	84.7	0.0	% Chart	84.8	0.1
high	404.00	85.8	85.2	-0.6	52.0			49.0		
full scale	500.00				100.0			100.0		
CO2					Avg.%			Avg.%		
zero	0.00	2.0	2.0	0.0	2.40	1.5	-0.5	2.50	2.2	0.2
low	3.22	18.1	18.0	-0.1	% Chart	18.2	0.1	% Chart	17.8	-0.3
mid	8.07	42.4	42.0	-0.4						
high	18.05	92.3	92.0	-0.3	14.0			14.5		
full scale	20.00				20.0			20.0		

	CERTIFIED GAS INPUT		TEST	ZERO and SPAN CALIBRATION CHECK		TEST	ZERO and SPAN CALIBRATION CHECK		TEST	ZERO and SPAN CALIBRATION CHECK	
	Concentration (% or ppm)	Target (% Chart)	RUN C-3	Final (% Chart)	Drift (% Chart)	RUN C-4	Final (% Chart)	Drift (% Chart)	RUN C-5	Final (% Chart)	Drift (% Chart)
NOx			Avg. ppm			Avg. ppm			Avg. ppm		
zero	0.00	2.0	25.0	2.0	0.0	27.0	2.0	0.0	27.0	2.5	0.5
low	19.70	11.9	% Chart			% Chart			% Chart		
mid	41.13	22.6	14.5			15.5			15.5		
high	160.90	82.5		82.5	0.0		82.2	-0.3		82.2	-0.3
full scale	200.00		200.0			200.0			200.0		
O2			Avg.%			Avg.%			Avg.%		
zero	0.00	10.0	16.65	10.0	0.0	16.18	10.0	0.0	16.18	10.0	0.0
low	4.03	26.1	% Chart			% Chart			% Chart		
mid	7.90	41.6									
high	18.10	82.4	76.6	82.3	-0.1	74.7	82.4	0.0	74.7	82.5	0.1
full scale	25.00		25.0			25.0			25.0		
CO			Avg. ppm			Avg. ppm			Avg. ppm		
zero	0.00	5.0	47.0	5.0	0.0	20.0	5.0	0.0	19.5	5.0	0.0
low	40.17	13.0									
mid	79.71	20.9	% Chart	84.7	0.0	% Chart	84.8	0.1	% Chart	84.8	0.1
high	404.00	85.8	52.0			25.0			24.5		
full scale	500.00		100.0			100.0			100.0		
CO2			Avg.%			Avg.%			Avg.%		
zero	0.00	2.0	2.50	2.2	0.2	2.70	1.8	-0.2	2.70	2.1	0.1
low	3.22	18.1	% Chart	17.5	-0.6	% Chart	17.8	-0.3	% Chart	18.1	0.0
mid	8.07	42.4									
high	18.05	92.3	14.5			15.5			15.5		
full scale	20.00		20.0			20.0			20.0		

Quality Assurance Worksheet: [redacted] TCP-3

	CERTIFIED GAS INPUT		TEST RUN C-6	ZERO and SPAN CALIBRATION CHECK		TEST RUN C-7	ZERO and SPAN CALIBRATION CHECK		TEST RUN C-8	ZERO and SPAN CALIBRATION CHECK	
	Concentration (% or ppm)	Target (% Chart)		Final (% Chart)	Drift (% Chart)		Final (% Chart)	Drift (% Chart)		Final (% Chart)	Drift (% Chart)
NOx			Avg. ppm			Avg. ppm			Avg. ppm		
zero	0.00	2.0	27.0	2.4	0.4	30.0	2.2	0.2	30.0	2.0	0.0
low	19.70	11.9	% Chart			% Chart			% Chart		
mid	41.13	22.6	15.5			17.0			17.0		
high	160.90	82.5		82.8	0.3		82.9	0.5		84.0	1.6
full scale	200.00		200.0			200.0			200.0		
O2			Avg.%			Avg.%			Avg.%		
zero	0.00	10.0	16.18	10.0	0.0	15.50	10.0	0.0	15.50	10.1	0.1
low	4.03	26.1	% Chart			% Chart			% Chart		
mid	7.90	41.6									
high	18.10	82.4	74.7	82.3	-0.1	72.0	82.6	0.2	72.0	82.4	0.0
full scale	25.00		25.0			25.0			25.0		
CO			Avg. ppm			Avg. ppm			Avg. ppm		
zero	0.00	5.0	20.0	5.2	0.2	19.5	5.0	0.0	6.5	5.0	0.0
low	40.17	13.0									
mid	79.71	20.9	% Chart	84.6	-0.1	% Chart	84.5	-0.2	% Chart	84.7	0.0
high	404.00	85.8	25.0			24.5			11.5		
full scale	500.00		100.0			100.0			100.0		
CO2			Avg.%			Avg.%			Avg.%		
zero	0.00	2.0	2.70	2.0	0.0	3.16	2.4	0.4	2.90	2.0	0.0
low	3.22	18.1	% Chart	18	-0.1	% Chart	17.4	-0.7	% Chart	17	-1.1
mid	8.07	42.4									
high	18.05	92.3	15.5			17.8			16.5		
full scale	20.00		20.0			20.0			20.0		

	CERTIFIED GAS INPUT		TEST	ZERO and SPAN CALIBRATION CHECK		TEST	ZERO and SPAN CALIBRATION CHECK		TEST	ZERO and SPAN CALIBRATION CHECK	
	Concentration (% or ppm)	Target (% Chart)	RUN **C-9**	Final (% Chart)	Drift (% Chart)	RUN **C-10**	Final (% Chart)	Drift (% Chart)	RUN **C-11**	Final (% Chart)	Drift (% Chart)
NOx			Avg. ppm			Avg. ppm			Avg. ppm		
zero	0.00	2.0	31.0	2.1	0.1	28.0	2.0	0.0	28.0	2.2	0.2
low	19.70	11.9	% Chart			% Chart			% Chart		
mid	41.13	22.6	17.5			16.0			16.0		
high	160.90	82.5		83.0	0.5		82.8	0.3		83.2	0.8
full scale	200.00		200.0			200.0			200.0		
O2			Avg.%			Avg.%			Avg.%		
zero	0.00	10.0	15.50	10.1	0.1	16.00	10.1	0.1	16.00	10.1	0.1
low	4.03	26.1	% Chart			% Chart			% Chart		
mid	7.90	41.6									
high	18.10	82.4	72.0	82.4	0.0	74.0	82.3	-0.1	74.0	82	-0.4
full scale	25.00		25.0			25.0			25.0		
CO			Avg. ppm			Avg. ppm			Avg. ppm		
zero	0.00	5.0	6.0	5.0	0.0	15.0	5.0	0.0	14.0	5.0	0.0
low	40.17	13.0									
mid	79.71	20.9	% Chart	84.5	-0.2	% Chart	84.3	-0.4	% Chart	84.4	-0.3
high	404.00	85.8	11.0			20.0			19.0		
full scale	500.00		100.0			100.0			100.0		
CO2			Avg.%			Avg.%			Avg.%		
zero	0.00	2.0	2.90	2.0	0.0	2.80	2.0	0.0	2.80	2.2	0.2
low	3.22	18.1	% Chart	17	-1.1	% Chart	18	-0.1	% Chart	17.5	-0.6
mid	8.07	42.4									
high	18.05	92.3	16.5			16.0			16.0		
full scale	20.00		20.0			20.0			20.0		

	CERTIFIED GAS INPUT		TEST	ZERO and SPAN CALIBRATION CHECK		TEST	ZERO and SPAN CALIBRATION CHECK		TEST	ZERO and SPAN CALIBRATION CHECK	
	Concentration (% or ppm)	Target (% Chart)	RUN C-12	Final (% Chart)	Drift (% Chart)	RUN C-13 (TO)	Final (% Chart)	Drift (% Chart)	RUN C-13 (JF)	Final (% Chart)	Drift (% Chart)
NOx			Avg. ppm			Avg. ppm			Avg. ppm		
zero	0.00	2.0	27.6	2.1	0.1	28.0	2.1	0.1	32.0	2.1	0.1
low	19.70	11.9	% Chart			% Chart			% Chart		
mid	41.13	22.6	15.8			16.0			18.0		
high	160.90	82.5		83.0	0.5		83.2	0.8		83.2	0.8
full scale	200.00		200.0			200.0			200.0		
O2			Avg.%			Avg.%			Avg.%		
zero	0.00	10.0	16.00	10.0	0.0	15.50	10.0	0.0	14.20	10.0	0.0
low	4.03	26.1	% Chart			% Chart			% Chart		
mid	7.90	41.6									
high	18.10	82.4	74.0	82	-0.4	72.0	82.3	-0.1	66.8	82.3	-0.1
full scale	25.00		25.0			25.0			25.0		
CO			Avg. ppm			Avg. ppm			Avg. ppm		
zero	0.00	5.0	14.5	5.0	0.0	4.0	5.1	0.1	6.0	5.1	0.1
low	40.17	13.0									
mid	79.71	20.9	% Chart	84.4	-0.3	% Chart	84.5	-0.2	% Chart	84.5	-0.2
high	404.00	85.8	19.5			9.0			11.0		
full scale	500.00		100.0			100.0			100.0		
CO2			Avg.%			Avg.%			Avg.%		
zero	0.00	2.0	2.80	2.0	0.0	3.10	2.5	0.5	3.80	2.5	0.5
low	3.22	18.1	% Chart	18	-0.1	% Chart	17.5	-0.6	% Chart	17.5	-0.6
mid	8.07	42.4									
high	18.05	92.3	16.0			17.5			27.3		
full scale	20.00		20.0			20.0			15.0		

	CERTIFIED GAS INPUT		TEST	ZERO and SPAN CALIBRATION CHECK		TEST	ZERO and SPAN CALIBRATION CHECK	
	Concentration (% or ppm)	Target (% Chart)	RUN C-14 (TO)	Final (% Chart)	Drift (% Chart)	RUN C-14 (JF)	Final (% Chart)	Drift (% Chart)
NOx			Avg. ppm			Avg. ppm		
zero	0.00	2.0	28.0	2.2	0.2	32.0	2.2	0.2
low	19.70	11.9	% Chart			% Chart		
mid	41.13	22.6	16.0			18.0		
high	160.90	82.5		83.0	0.5		83.0	0.5
full scale	200.00		200.0			200.0		
O2			Avg.%			Avg.%		
zero	0.00	10.0	15.50	10.0	0.0	14.25	10.0	0.0
low	4.03	26.1	% Chart			% Chart		
mid	7.90	41.6						
high	18.10	82.4	72.0	82.0	-0.4	67.0	82.0	-0.4
full scale	25.00		25.0			25.0		
CO			Avg. ppm			Avg. ppm		
zero	0.00	5.0	5.0	5.1	0.1	7.0	5.1	0.1
low	40.17	13.0						
mid	79.71	20.9	% Chart	84.6	-0.1	% Chart	84.6	-0.1
high	404.00	85.8	10.0			12.0		
full scale	500.00		100.0			100.0		
CO2			Avg.%			Avg.%		
zero	0.00	2.0	3.06	2.1	0.1	3.70	2.1	0.1
low	3.22	18.1	% Chart	18	-0.1	% Chart	18	-0.1
mid	8.07	42.4						
high	18.05	92.3	17.3			20.5		
full scale	20.00		20.0			20.0		

Quality Assurance Worksheet: [redacted] TCP-3

	CERTIFIED GAS INPUT		TEST	ZERO and SPAN CALIBRATION CHECK		TEST	ZERO and SPAN CALIBRATION CHECK	
	Concentration (% or ppm)	Target (% Chart)	RUN C-15 (TO)	Final (% Chart)	Drift (% Chart)	RUN C-15 (JF)	Final (% Chart)	Drift (% Chart)
NOx			Avg. ppm			Avg. ppm		
zero	0.00	2.0	29.0	2.0	0.0	33.0	2.2	0.2
low	19.70	11.9	% Chart			% Chart		
mid	41.13	22.6	16.5			18.5		
high	160.90	82.5		82.6	0.1		82.6	0.1
full scale	200.00		200.0			200.0		
O2			Avg.%			Avg.%		
zero	0.00	10.0	15.55	10.0	0.0	14.25	10.0	0.0
low	4.03	26.1	% Chart			% Chart		
mid	7.90	41.6						
high	18.10	82.4	72.2	82.4	0.0	67.0	82.4	0.0
full scale	25.00		25.0			25.0		
CO			Avg. ppm			Avg. ppm		
zero	0.00	5.0	5.0	5.1	0.1	7.0	5.1	0.1
low	40.17	13.0						
mid	79.71	20.9	% Chart	84.6	-0.1	% Chart	84.4	-0.3
high	404.00	85.8	10.0			12.0		
full scale	500.00		100.0			100.0		
CO2			Avg.%			Avg.%		
zero	0.00	2.0	3.04	2.0	0.0	3.72	2.0	0.0
low	3.22	18.1	% Chart	17.9	-0.2	% Chart	17.9	-0.2
mid	8.07	42.4						
high	18.05	92.3	17.2			20.6		
full scale	20.00		20.0			20.0		

Thermo Electron CORPORATION

Richard A. Curran
Regional Sales Manager

Environmental Instruments Division

108 South Street
Hopkinton, Massachusetts 01748
(617) 435-5321

INTERFERENCE RESPONSE TEST

DATE OF TEST JAN 18, 1980

ANALYZER TYPE 10AR RANGE 0-25PPM SERIAL NO. 10AR-014B-80

TEST GAS TYPE	CONCENTRATION PPM	ANALYZER OUTPUT RESPONSE	% OF SPAN
CO	500	< .1 PPM	<.1%
CO_2	201	< .1 PPM	< .1%
CO_2	10%	< .1PPM	<.1%
O_2	20.9%	<.1PPM	<.1%

Continous Emission Analyzer Interference Response Tests

Date: 7/8/88
Technician: KRB / JMM

Analyzer Type: Thermo Environmental
Analyzer Model: Model 48 Gas Filter Correlation Analyzer
Serial Number: 48-23576-210
Analyzer Test Range: 0-20 ppmV

Test Gas		Analyzer Response		Response
Type Gas	Concentration	Concentration ppmv	% of Range	Ratio
Air	CO Free	0.0	N/A	
CO_2/O_2	4%/18%	0.0		0.000
CO_2/O_2	12%/8%	-0.2		-0.017/-0.025
CO_2/O_2	21%/3%	-0.3		-0.014/-0.100
Air	Dry	0.4		CO Impurity?
NOx	176 ppmV	0.4		0.002
NOx	3030 ppmV	0.4		0.0001
SO_2	401 ppmV	-0.2		0.0005
Propane	240 ppmV	0.4		0.002

ppmv/%

ppmv/ppmv

all interferences are negligable

Response Time Data Sheet

Date: 6-30-92

Location: _

Technician: RK, LI, TS

Sample Manifold: 3.0 psig

Pump Model: G-3 Dia-Pump

Sample Line Length 100' ft.

Heat Trace Length 90' ft.

Condenser Design: Iglon #5

Analyzer Type:	NOx	O2	
Make/Model:	TECO 10 AR	Servomex 1400	
Range:	0-200 ppm	0-20%	
Span Gas:	Stack gas (TCP-3)	Stack Gas (TCP-3)	
Upscale Response:			
Trial 1	.84 min	.91 min	
Trial 2	.86 min	.93 min	
Trial 3	.89 min	.93 min	
Average	.86 min.	.92 min	
Downscale Response:			
Trial 1	.89 min	.93 min	
Trial 2	.86 min	.96 min	
Trial 3	.89 min	.98 min	
Average	.88 min	.96 min	

Comments:

APPENDIX D: EXAMPLE CALIBRATION CERTIFICATIONS

Matheson
Gas Products
World Leader in Specialty Gases & Equipment

RECEIVED DEC 1 7 1992

CERTIFICATE OF ANALYSIS-EPA PROTOCOL MIXTURES

CUSTOMER: WILSON OXYGEN AND SUPPLY — REFERENCE #: 109-16269

CYLINDER #: SX-25924 — PROTOCOL: 1

CYLINDER PRESSURE: 1800

LAST ANALYSIS DATE: 12/14/92

EXPIRATION DATE: 06/14/94

		REPLICATE CONCENTRATIONS	
COMPONENT : NITRIC OXIDE		DATE: 12/07/92	DATE: 12/14/92
MEAN CONC : 6.82 PPM		6.86 PPM 6.89 PPM 6.79 PPM	6.83PPM 6.78PPM 6.72PPM
COMPONENT : NITROGEN DIOXIDE		DATE: / /	DATE: / /
MEAN CONC : 0.25 PPM			
COMPONENT :		DATE: / /	DATE: / /
MEAN CONC :			

BALANCE GAS: NITROGEN

ACCEPTED BY

WILSON OXYGEN

REFERENCE STANDARDS

SRM # : 2628A

CYLINDER # : CLM-4176

CONCENTRATION: 9.75 PPM

1650 Enterprise Parkway
P.O. Box 358
Twinsburg, Ohio 44087
Phone: (216) 425-4406
Toll Free: (800) 426-9427

BEST AVAILABLE COPY

ALPHAGAZ

DIVISION OF LIQUID AIR CORPORATION

10-Aug-92 P.O. NO.: 128072992

BIG THREE INDUSTRIES AUSTIN, TX

CERTIFICATION OF CYLINDER # CC-115214

COMPONENT:	MEAN CONCENTRATION:
NITRIC OXIDE	19.3 +/- 1.3 ppm
Total NOx	19.9 ppm
NITROGEN	BALANCE

Cylinder pressure:	1800 psig
Expiration date:	10-Feb-94

This mixture was prepared and analyzed following EPA Revised Traceability Protocol No.1, Section 3.0.4, per Procedure G1. The concentration of the Nitric Oxide was determined by direct comparison with NIST SRM 1683b, Sample No.:45-12-P, S/N CLM-2231, 47.6 +/- 0.7 ppm Nitric Oxide in Nitrogen, dated October 31, 1991. The analysis was performed on a Beckman 951A chemiluminescent-type analyzer measuring the reaction of Nitric Oxide with Ozone. S/N 00100508, 0-100 ppm range. The last multipoint calibration was done on August 3, 1992.

Moses Choi

Authorized signature

2445 South Street • P.O. Box 5548 • Long Beach, CA 90805 • Phone (213) 492-5300 • Fax (213) 492-5349

BEST AVAILABLE COPY

ALPHAGAZ

DIVISION OF LIQUID AIR CORPORATION

10-Aug-92
BIG THREE INDUSTRIES

P.O. NO.: 128072992
AUSTIN, TX

CERTIFICATION OF CYLINDER # CC-115228

COMPONENT:	MEAN CONCENTRATION:
NITRIC OXIDE	41.2 +/- 1.3 ppm
Total NOx	42.6 ppm
NITROGEN	BALANCE

Cylinder pressure:	1800 psig
Expiration date:	10-Feb-94

This mixture was prepared and analyzed following EPA Revised Traceability Protocol No.1, Section 3.0.4, per Procedure G1. The concentration of the Nitric Oxide was determined by direct comparison with NIST SRM 1683b, Sample No.:45-12-P, S/N CLM-2231, 47.6 +/- 0.7 ppm Nitric Oxide in Nitrogen, dated October 31, 1991. The analysis was performed on a Beckman 951A chemiluminescent-type analyzer measuring the reaction of Nitric Oxide with Ozone. S/N 00100508, 0-100 ppm range. The last multipoint calibration was done on August 3, 1992.

Authorized signature

2445 South Street • P.O. Box 5548 • Long Beach, CA 90805 • Phone (213) 492-5300 • Fax (213) 492-5349

Scott Specialty Gases, Inc.

1290 COMBERMERE STREET, TROY, MI 48083 (313) 589-2950 FAX: (313) 589-2134

CERTIFICATE OF ANALYSIS: EPA PROTOCOL GAS

Customer	Assay Laboratory		
CUBIX CORPORATION	Scott Specialty Gases, Inc.	Purchase Order	JOHN WETHEROLD
9225 LOCKHART HWY	1290 Combermere	Scott Project #	550913
AUSTIN TX 78747	Troy, MI 48083		

ANALYTICAL INFORMATION

Certified to exceed the minimum specifications of EPA Protocol 1 Procedure # G1, Section Number 3.0.4

Cylinder Number	ALM005440	Certification Date	5-17-93	General Exp. Date	5-17-95
Cylinder Pressure	1900 psig	Previous Certification Dates	None	Acid Rain Exp. Date	11-17-94

ANALYZED CYLINDER

Components	Certified Concentration	Analytical Uncertainty*
Nitric Oxide	80.10 ppm	±1% NIST Directly Traceable
Total Oxides of Nitrogen	80.80 ppm	Reference Value Only
Balance Gas: Nitrogen		

*Analytical uncertainty is inclusive of usual known error sources which at least includes reference standard error & precision of the measurement processes.

REFERENCE STANDARD

Type	Expiration Date	Cylinder Number	Concentration
SRM 1684B	1-6-94	CIM002155	95.10 ppm NO in N_2

INSTRUMENTATION

Instrument/Model/Serial #	Last Date Calibrated	Analytical Principle
NO: Horiba/OPE-235/483814	4-12-93	Chemiluminescence

ANALYZER READINGS (Z=Zero Gas R=Reference Gas T=Test Gas r=Correlation Coefficient)

Components	First Triad Analysis	Second Triad Analysis	Calibration Curve
Nitric Oxide	Date: 5-10-93 Response Units: mv Z1=0.00 R1=95.10 T1=80.00 R2=95.10 Z2=0.00 T2=80.00 Z3=0.00 T3=80.00 R3=95.10 Avg. Conc. of Cust. Cyl. 80.00 ppm	Date: 5-17-93 Response Units: mv Z1=0.00 R1=95.10 T1=80.20 R2=95.10 Z2=0.00 T2=80.20 Z3=0.00 T3=80.20 R3=95.10 Avg. Conc. of Cust. Cyl. 80.20 ppm	Concentration=$A+Bx+Cx^2+Dx^3+Ex^4$ r=0.99999 SRM 1684B Constants: A=-0.000967384 B=1.000115 C=0 D=0 E=0
			Concentration=$A+Bx+Cx^2+Dx^3+Ex^4$
			Concentration=$A+Bx+Cx^2+Dx^3+Ex^4$

Special Notes

If this product is used for Acid Rain Rule Compliance, the *Acid Rain Expiration Date* noted above applies per 40 CFR Part 75, Appendix H. Otherwise, the *General Expiration Date* applies.

F. P. Doran

Analyst Frank P. Doran

Scott Specialty Gases, Inc.

1290 COMBERMERE STREET, TROY, MI 48083 (313) 589-2950 FAX: (313) 589-2134

CERTIFICATE OF ANALYSIS: EPA PROTOCOL GAS

Customer
CUBIX CORPORATION
9225 LOCKHART HWY
AUSTIN, TX, 78747

Assay Laboratory
Scott Specialty Gases, Inc.
1290 Combermere
Troy, MI 48083

Purchase Order 93401
Scott Project # 553985

ANALYTICAL INFORMATION

Certified to exceed the minimum specifications of EPA Protocol 1 Procedure # G1, Section Number 3.0.4

Cylinder Number ALM038818
Cylinder Pressure 1900 psig
Certification Date 8-9-93
Previous Certification Dates None
General Exp. Date 8-9-95
Acid Rain Exp. Date 8-9-95

ANALYZED CYLINDER

Components	Certified Concentration	Analytical Uncertainty*
Nitric Oxide	160.4 ppm	±1% NIST Directly Traceable
Total Oxides of Nitrogen	160.4 ppm	Reference Value Only
Balance Gas: Nitrogen		

*Analytical uncertainty is inclusive of usual known error sources which at least includes reference standard error & precision of the measurement processes.

REFERENCE STANDARD

Type	Expiration Date	Cylinder Number	Concentration
CRM	3-5-97	ALM024135	244.7 PPM $N0/N_2$

INSTRUMENTATION

Instrument/Model/Serial #	Last Date Calibrated	Analytical Principle
NO: Beckman/951A/270-082899B	6-21-93	Chemiluminescence

ANALYZER READINGS (Z=Zero Gas R=Reference Gas T=Test Gas r=Correlation Coefficient)

Components	First Triad Analysis	Second Triad Analysis	Calibration Curve
Nitric Oxide	Date: 8-2-93 Response Units: mv Z1=0.00 R1=97.80 T1=64.10 R2=97.80 Z2=0.00 T2=64.10 Z3=0.00 T3=64.10 R3=97.80 Avg. Conc. of Cust. Cyl. 160.4 ppm	Date: 8-9-93 Response Units: mv Z1=0.00 R1=97.80 T1=64.10 R2=97.80 Z2=0.00 T2=64.10 Z3=0.00 T3=64.10 R3=97.80 Avg. Conc. of Cust. Cyl. 160.4 ppm	$Concentration=A+Bx+Cx^2+Dx^3+Ex^4$ r=0.99999 SRM 1685 Constants: A=0.008456338 B=2.502916 C=0 D=0 E=0
			$Concentration=A+Bx+Cx^2+Dx^3+Ex^4$
			$Concentration=A+Bx+Cx^2+Dx^3+Ex^4$

Special Notes
If this product is used for Acid Rain Rule Compliance, the *Acid Rain Expiration Date* noted above applies per 40 CFR Part 75, Appendix H. Otherwise, the *General Expiration Date* applies.

Tim Sanderson
Analyst Tim Sanderson

BEST AVAILABLE COPY

Scott Specialty Gases, Inc.

1290 COMBERMERE STREET TROY, MI 48083 PHONE: (313) 589-2950 FAX NO: (313) 589-2134

CUBIX CORPORATION
9225 LOCKHART HWY
AUSTIN TX 78747

Date: 2/3/92

Our Project No.: 052883

Your P.O. No.: 910471

Gentlemen:

Thank you for choosing Scott for your Specialty gas needs. The analyses for the gases ordered, as reported by our laboratory, are listed below. Results are in volume percent, unless otherwise indicated.

ANALYTICAL REPORT

Cyl. No. ALM018473 Analytical Accuracy +/-1%

Component	Concentration
CARBON MONOXIDE	79.71ppm
METHANE	79.64ppm
BALANCE	AIR
ACUBLEND MASTER GAS	

Cyl. No AAL20862 Analytical Accuracy +/-1%

Component	Concentration
CARBON MONOXIDE	8.066ppm
METHANE	7.998ppm
BALANCE	AIR
ACUBLEND MASTER GAS	

Cyl. No. ALM016314 Analytical Accuracy +/-1%

Component	Concentration
CARBON MONOXIDE	40.17ppm
METHANE	39.77ppm
BALANCE	AIR
ACUBLEND MASTER GAS	

Cyl. No. ______ Analytical Accuracy ______

Component	Concentration

Analyst [signature]

Approved [signature]

The only liability of this Company for gas which fails to comply with this analysis shall be replacement thereof by the Company without extra cost.

Scott Specialty Gases, Inc.

Shipped From: 3714 LAPAS DRIVE
HOUSTON TX 77023
Phone: 713-644-4820 Fax: 713-644-0244

CERTIFICATE OF ANALYSIS

CUBIX CORPORATION

9225 LOCKHART HWY

AUSTIN TX 78747

PROJECT #: 04-19430
PO#: 92373
ITEM #: 04024311 1AL
DATE: 9/01/92

CYLINDER #: ALM003153 ANALYTICAL ACCURACY: +/- 1%

COMPONENT	REQUESTED GAS CONC MOLES		ANALYSIS (MOLES)	
CARBON MONOXIDE	15.	PPM	15.0	PPM
METHANE	15.	PPM	14.9	PPM
AIR		BAL		BAL

ANALYTICAL METHOD: GRAV.MASTER GAS

ANALYST: Rene Flores APPROVED BY: [signature]
ANALYST SUPERVISOR

PLUMSTEADVILLE, PENNSYLVANIA / TROY, MICHIGAN / HOUSTON, TEXAS / DURHAM, NORTH CAROLINA
SOUTH PLAINFIELD, NEW JERSEY / FREMONT, CALIFORNIA / WAKEFIELD, MASSACHUSETTS / LONGMONT, COLORADO
BATON ROUGE, LOUISIANA

Best Available Copy

ALPHAGAZ
DIVISION OF LIQUID AIR CORPORATION

ALPHAGAZ

SPECIALTY GAS DIVISION

P.O. Box 1026
11426 Fairmont Pkwy.
La Porte, Texas 77571

Phone (713) 474-8400
Fax (713) 474-8419
USA (800) 248-1427

25 August 1992

Customer: BIG 3 AUSTIN

P.O. Number : 128072992B
AGZ Document: #1425283

Valve Type .: CGA 590

CERTIFICATION OF CYLINDER # CC79058

Component	MOLE %
METHANE	2.1 PPM
CARBON MONOXIDE	2.8 PPM
AIR	BALANCE

Re-certification date: 25 August 1993

Prepared By: Mary Payne

Scott Specialty Gases, Inc.

3714 LAPAS DRIVE, HOUSTON, TX 77023-0000
PHONE: 713-644-4820 FAX: 713-644-0244

10/14/91

CUBIX CORPORATION
9225 LOCKHART HWY

AUSTIN TX 78747-0000

PROJECT #: 04-13615
PO #: 910471

CYLINDER #: AAL13947

ANALYTICAL ACCURACY: +-1%

COMPONENT	REQUESTED CONCENTRATION	ANALYSIS (MOLES) U/M
CARBON DIOXIDE	3.2 PCT	3.22 PCT
OXYGEN	18.0 PCT	18.10 PCT
NITROGEN	BALANCE	BALANCE

NOTES:

ANALYTICAL METHOD: ACUBLEND MASTER

DATE OF ANALYSIS: 10/14/91

ANALYST: [illegible]
ANALYST

APPROVED BY: John Sempe
SUPERVISOR

Best Available Copy

Scott Specialty Gases, Inc.

3714 LAPAS DRIVE, HOUSTON, TX 77023-0000
PHONE: 713-644-4820 FAX: 713-644-0244

10/14/91

CUBIX CORPORATION
9225 LOCKHART HWY

AUSTIN TX 78747-0000

PROJECT #: 04-13615
PO #: 910471

CYLINDER #: AAL268

ANALYTICAL ACCURACY: +-1%

COMPONENT	REQUESTED CONCENTRATION		ANALYSIS (MOLES)	U/M
ARBON DIOXIDE	8.0	PCT	8.07	PCT
X GEN	8.0	PCT	7.90	PCT
I ROGEN	BALANCE		BALANCE	

NOTES:

ANALYTICAL METHOD: ACUBLEND MASTER

DATE OF ANALYSIS: 10/14/91

ANALYST: [signature]
ANALYST

APPROVED BY: John Sempe
SUPERVISOR

Best Available Copy

Scott Specialty Gases, Inc.

3714 LAPAS DRIVE, HOUSTON, TX 77023-0000 10/14/91
PHONE: 713-644-4820 FAX:713-644-0244

CUBIX CORPORATION
9225 LOCKHART HWY
AUSTIN TX 78747-0000

PROJECT #: 04-13615
PO #: 910471

CYLINDER #: AAL20488 ANALYTICAL ACCURACY: +-1%

COMPONENT	REQUESTED CONCENTRATION		ANALYSIS 1 (MOLES)	U/M
CARBON DIOXIDE	18.0	PCT	18.05	PCT
OXYGEN	4.0	PCT	4.03	PCT
NITROGEN	BALANCE		BALANCE	

NOTES:

ANALYTICAL METHOD: ACUBLEND MASTER

DATE OF ANALYSIS: 10/14/91

ANALYST: John P. McCulloch
ANALYST

APPROVED BY: John Sempe
SUPERVISOR

APPENDIX E:
PROPOSED TEST SCHEDULE

TEST SCHEDULE NOT DETERMINED YET

APPENDIX F:
PLOT PLAN, STACK DIAGRAM
STACK TRAVERSE LAY-OUTS

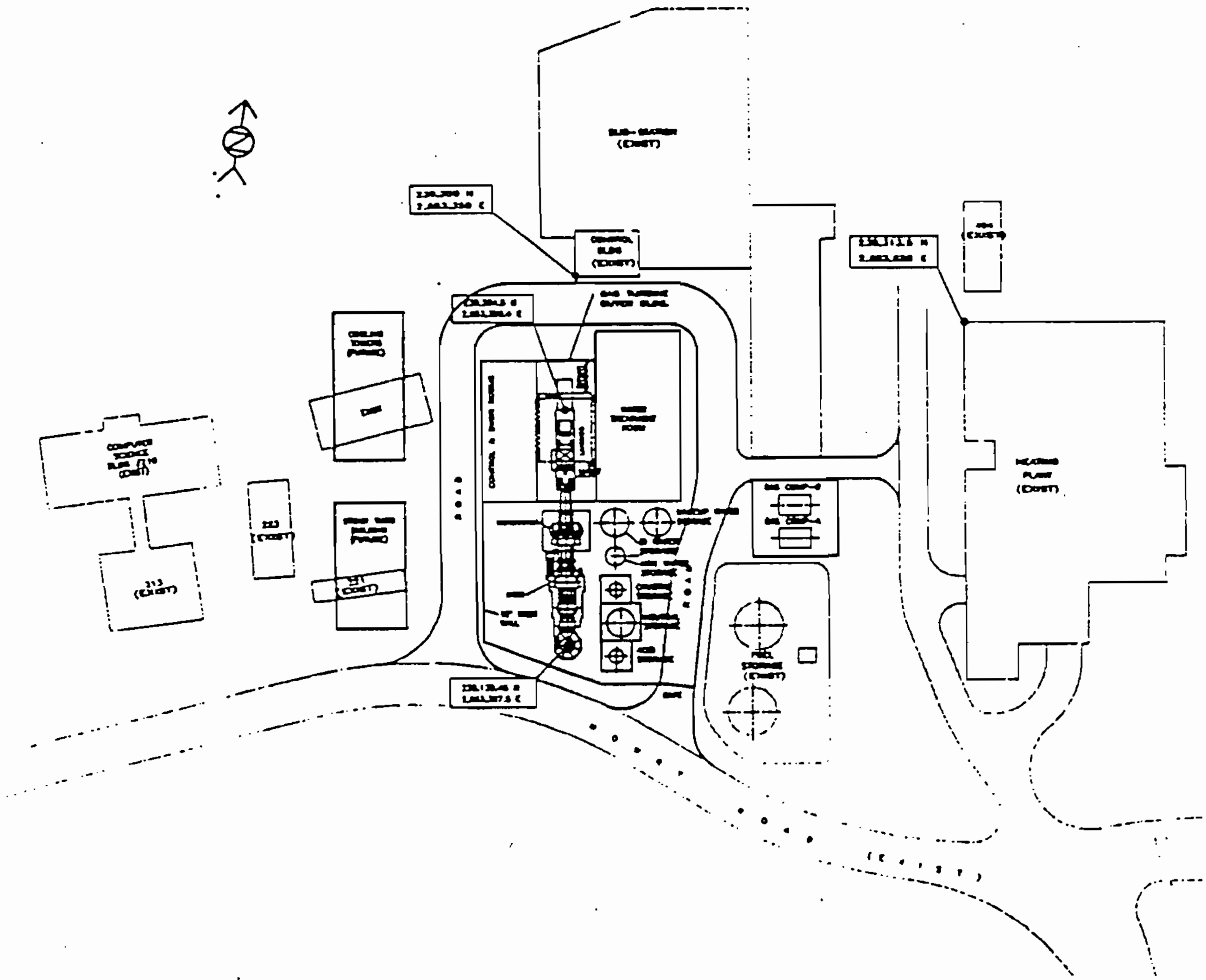
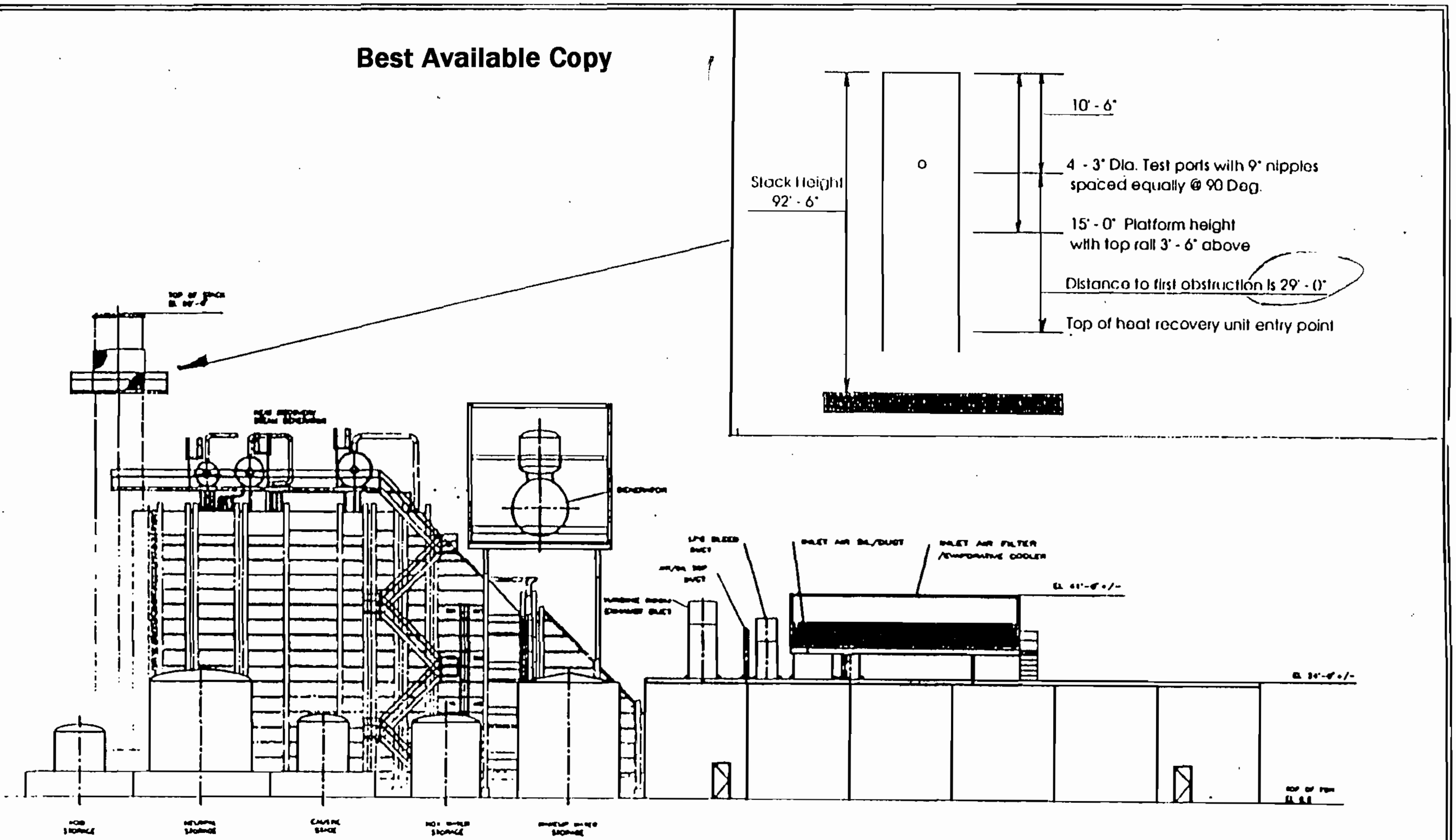


Figure 5. Site Plan of the University of Florida Co-Generation Unit

Florida Power
CORPORATION

Best Available Copy

Figure 6. Stack sampling port location
University of Florida Co-Gen Unit



EAST ELEVATION

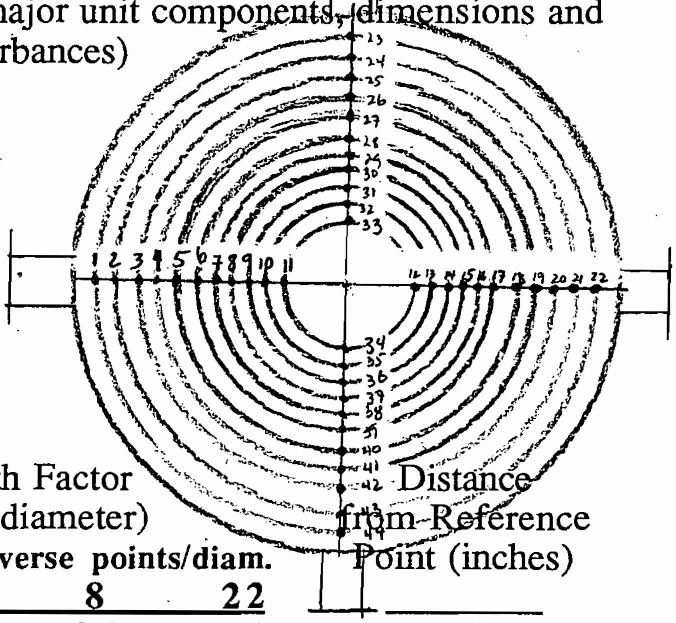
Florida Power
CORPORATION

Circular Stack Sampling Traverse Point Layout
(EPA Method 1)

Date:______________________________
Plant: FPC : University of Florida
Source: GE LM-6000
Technician(s):______________________

Port + Stack ID:_____126______in.
Port Extension:_______9_______in.
Stack ID:___________117______in.
Stack Area:________74.66_____ft^2
Total Req'd Traverse Points:__44__
No. of Traverse Points:__22_/diam.
No. of Traverse Points:__22_ /port

Stack Diagram (Side View showing major unit components, dimensions and nearest upstream and downstream disturbances)



Traverse Point Number	Length Factor (% of diameter) Number of traverse points/diam. 4	6	8	22	Distance from Reference Point (inches)
1	6.7	4.4	3.2	1.1	10.29
2	25.0	14.6	10.5	3.5	13.10
3	75.0	29.6	19.4	6.0	16.02
4	93.3	70.4	32.3	8.7	19.18
5		85.4	67.7	11.6	22.57
6		95.6	80.6	14.6	26.08
7			89.5	18.0	30.06
8			96.8	21.8	34.51
9				26.2	39.65
10				31.5	45.86
11				39.3	54.98
12				60.7	80.02
				68.5	89.15
				73.8	95.35
				78.2	100.05
				82.0	104.94
				85.4	108.92
				88.4	112.43
				91.3	115.82
				94.0	118.98
				96.5	121.91
				98.9	124.71

Table 4 University of Florida Co-Generation Data

Address:

Mowry Road, Building No. 82
University of Florida
Gainesville, Florida

Unit Description:

One Combustion Turbine(CT) and one Heat Recovery Steam Generator(HRSG) is under construction at this site.

The CT unit is a General Electric Model LM 6000 and fired by natural gas with steam injection for NO_x control to 25 PPMVD at 15% oxygen.

The CT is rated at 43.3 MW on natural gas.

The HRSG unit operates on the CT exhaust gases and is supplementally fired on natural gas using duct burners to generate steam only.

Exhaust Stack Information:

Height:	93 Ft.
Diameter:	9.75 Ft. (Round stack)
Gas Flow:	325,200 ACFM
Velocity	72.6 FPS
Exit Temp.:	257 ^{o} F (combine output of both CT & HRSG units)

Drawings:

The location of the site is shown in Figure 4.
The site layout is shown in Figure 5.
The exhaust stack test port location is shown in Figure 6.

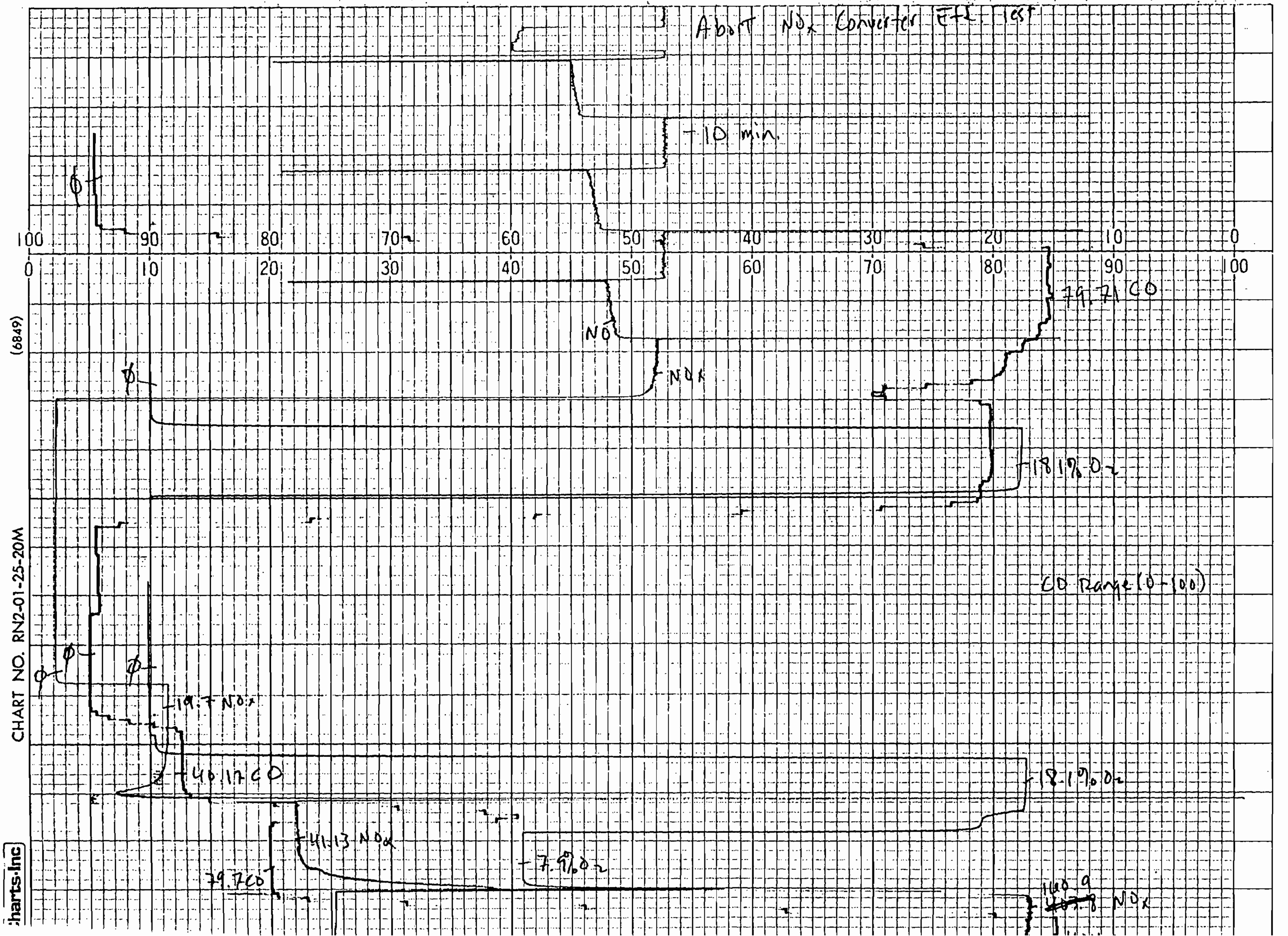
Authorized Air Permit:

The Florida Department of Environmental Regulation (FDER) Air Construction Permit No. is AC 01-204652.

APPENDIX G: EXAMPLE STRIP CHART RECORDS

NOX, CO, O_2

Best Available Copy



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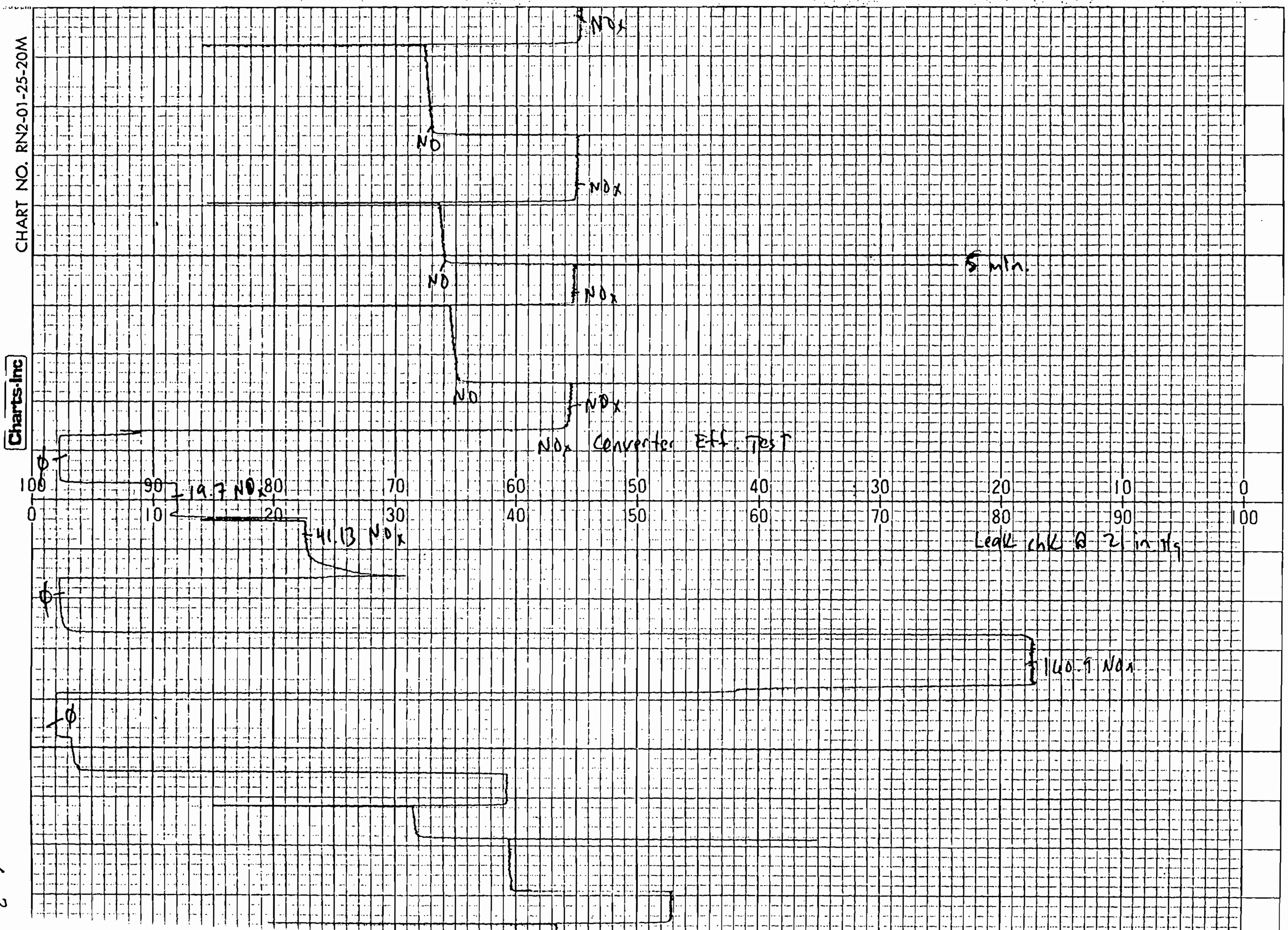
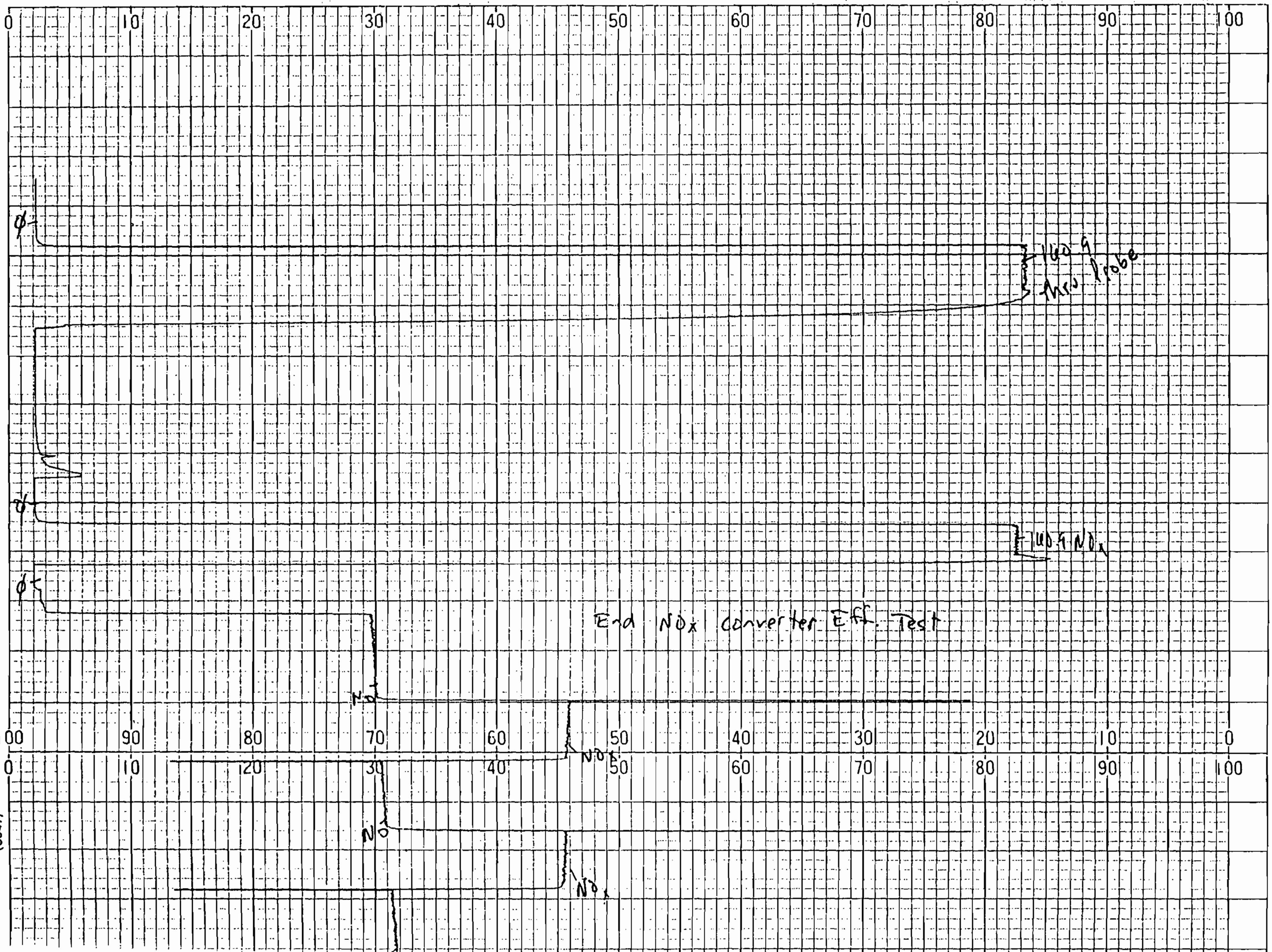


6-3


160.9 thru Probe
160.9 NOx
End NOx Converter Eff. Test
NO
NOx
NO
NOx

(6849)

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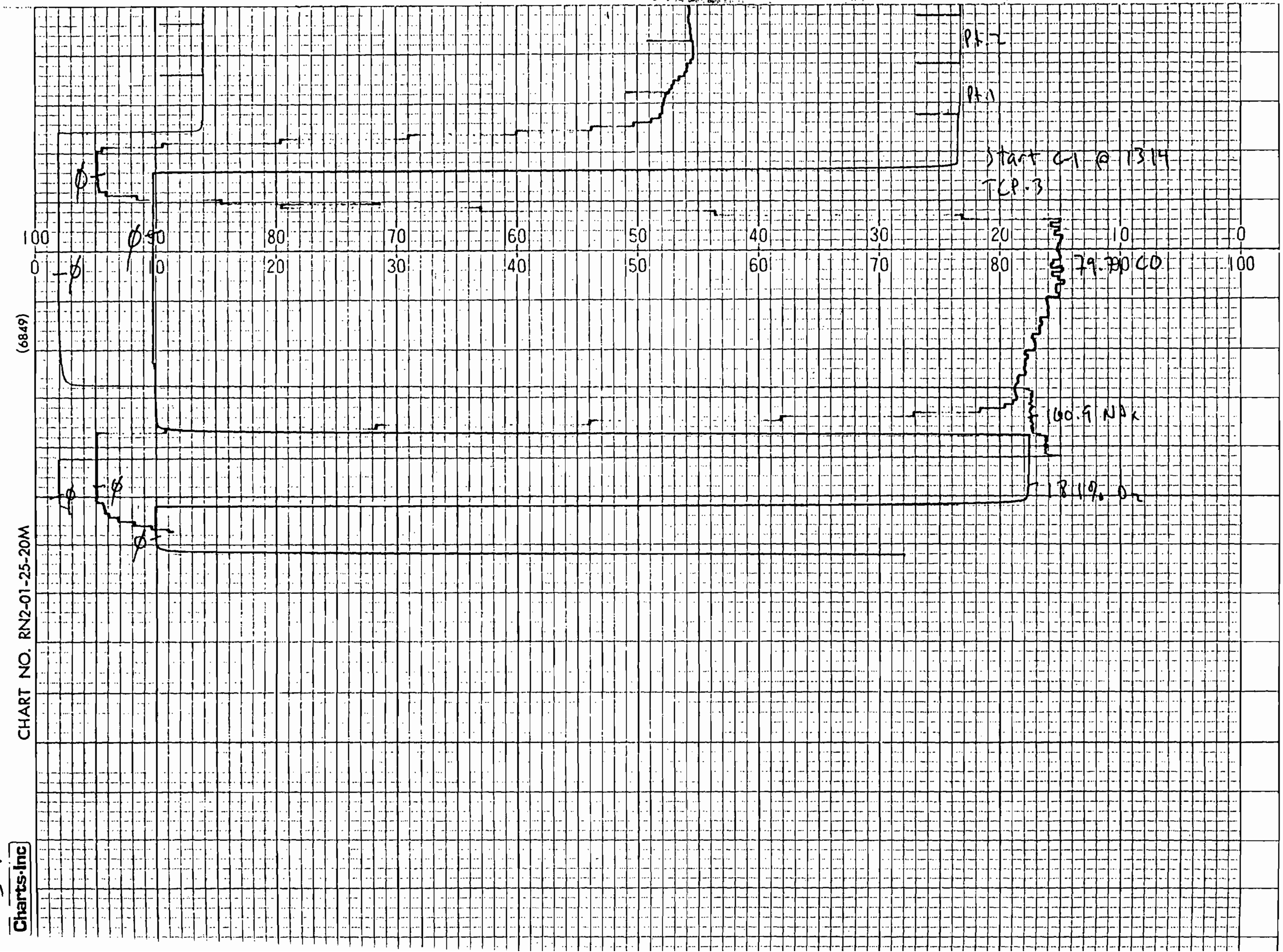

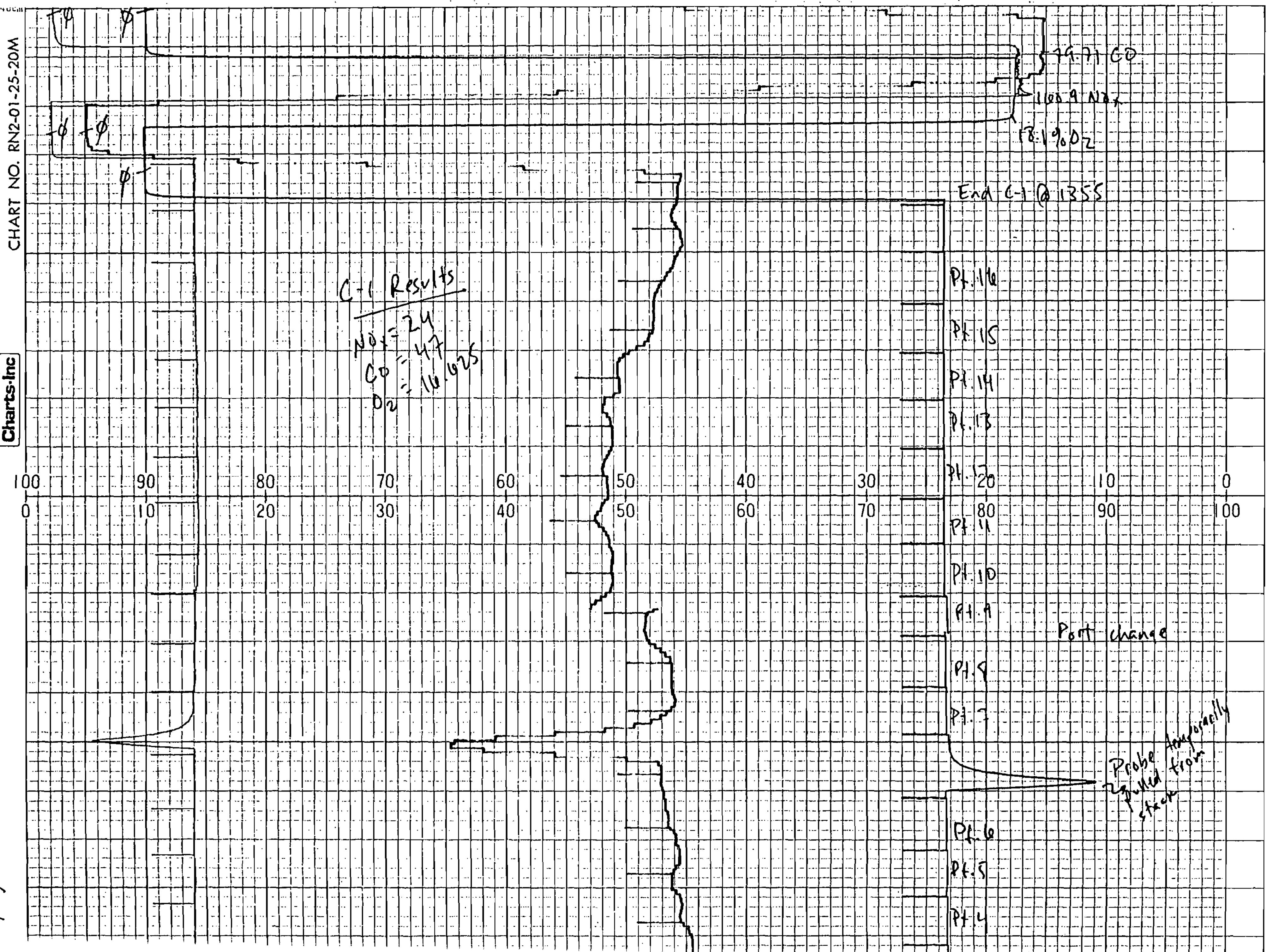

CHART NO. RN2-01-25-20M
Charts-Inc
79.71 CO
100.9 NOx
18.1% O2
End C-1 @ 1355
C-1 Results
NOx = 24
CO = 47
O2 = 16.625
Pt. 16
Pt. 15
Pt. 14
Pt. 13
Pt. 12
100 90 80 70 60 50 40 30 20 10 0
0 10 20 30 40 50 60 70 80 90 100
Pt. 11
Pt. 10
Pt. 9
Port change
Pt. 8
Pt. 7
Probe temporarily pulled from stack
Pt. 6
Pt. 5
Pt. 4

6-9


End C-2 @ 1438
C-2 Results
NOx = 25
CO = 44
O2 = 16.625
Pt. 8
Pt. 7
Pt. 6
Pt. 5
Pt. 4
Pt. 3
Pt. 2
Pt. 1
Start C-2 @ 1405

(6849)

G-7

Patty copy and file

Florida Power CORPORATION

RECEIVED

DEC - 9 1993

Division of Air Resources Management

December 3, 1993

Mr. Chris Kirts
Air Program Manager, Northeast District
7825 Bay Meadows Way
Suite B200
Jacksonville, Florida 32256

Dear Mr. Kirts:

Re: Initial Startup of New Combustion Turbine at the University of Florida
DEP Permit No. AC01-204652

As required by 40 CFR 60, Florida Power Corporation (FPC) is providing the Department of Environmental Protection (DEP) notification of the initial startup of the new combustion turbine at FPC's University of Florida Cogeneration facility. The initial startup is scheduled for December 17, 1993. FPC will subsequently notify your agency of the actual date that startup occurred.

Please feel free to contact me at (813) 866-5158 if you have any questions or if you need additional information.

Sincerely,

Scott H. Osbourn
Senior Environmental Engineer

cc: Mr. John Brown, DEP Tallahassee

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

FLORIDA POWER CORPORATION,

Petitioners,

vs. OGC CASE NO. 91-1113

FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION,

Respondents.
_______________________________/

RECEIVED
AUG 13 1992
Dept. of Environmental Reg.
Office of General Counsel

SETTLEMENT STIPULATION

RECITALS

WHEREAS, The Technical Evaluation and Preliminary Determination for permit No. AC01-203652 to construct a 43 magawatt cogeneration facility at the University of Florida was distributed on June 30, 1992;

WHEREAS, the Notice of Intent to Issue was published in the Gainesville Sun on July 3, 1992 and copies of the evaluation were available for public inspection at the Department's Tallahassee and Jacksonville offices;

WHEREAS, comments were submitted by the applicant on July 29, 1992, requesting modification of Specific Conditions Nos. 3, 4, and 7; and

WHEREAS, applicant's proposals require modifications to the permit which must first be approved by the Department before such modifications may be implemented.

STIPULATION

The Petitioners, Florida Power Corporation, and the Respondents, Florida Department of Environmental Regulation, agree to the following in settlement of the above-styled proceeding:

1. The Department shall modify construction permit No. AC 01-204652 for the construction of a 43 magawatt congeneration facility as follows (see Exibit 1):

(a) Specific Condition No. 3 - Specific limits for Boilers 4 and 5 were replaced with a total NOx cap to provide operational flexibility in the event of gas curtailments.

(b) Specific Condition No. 4 - The required operating rate during the compliance test was modified to reflect the maximum capacity achievable at a given ambient temperature.

(c) Specific Condition No. 7 - Language was added to clarify that a revised BACT analysis is dependent on the facility meeting the emission limits

2. By execution of this Agreement, the Petitioner agrees to withdraw opposition to all permit conditions issued in construction permit No. AC 01-204652.

W. Jeffrey Pardue

DATE: 8-11-92

Jefferson M. Braswell
COUNSEL FOR FDER

DATE: 8/14/92

Scott Osbourn

DATE: 8/11/92

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by U.S. Mail to:

W. Jeffery Pardue
Scott Osbourn
Environmental Programs
Florida Power Corporation
Post Office Box 14042
St. Petersburg, Florida 33733

on this 14th day of August, 1992.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

JEFFERSON M. BRASWELL
Assistant General Counsel
Florida Bar No. 800996

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

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION
NOTICE OF PERMIT

In the matter of an
Application for Permit by:

DER File No. AC 01-204652
PSD-FL-181
Alachua County

Mr. R. W. Neiser
Florida Power Corporation
3201-34th Street South
St. Petersburg, Florida 33733
_______________________________/

Enclosed is Permit Number AC 01-204652 to construct a 43 MW cogeneration facility at the University of Florida's Central Heat Plant facility in Gainesville, Alachua County, Florida, issued 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 30 days from the date this Notice is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

____
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 ____________________ 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) _______________ (Date)

Copies furnished to:
- A. Kutyna, NED
- J. Harper, EPA
- C. Shaver, NPS
- K. Kosky, P.E.

EXHIBIT 1

Final Determination

Florida Power Corporation/University of Florida Cogeneration Project
Alachua County, Florida

Permit No. AC 01-204652
PSD-FL-181

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

August 7, 1992

Final Determination

The Technical Evaluation and Preliminary Determination for the permit to construct a 43 megawatt cogeneration facility at the University of Florida Central Heat Plant in Gainesville, Alachua County, Florida, was distributed on June 30, 1992. The Notice of Intent to Issue was published in the Gainesville Sun on July 3, 1992. Copies of the evaluation were available for public inspection at the Department's Tallahassee and Jacksonville offices.

Comments were submitted by the applicant on July 29, 1992, requesting modification of Specific Conditions Nos. 3, 4, and 7. The Department made the following changes in response to those comments:

Specific Condition No. 3 - Specific limits for Boilers 4 and 5 were replaced with a total NO_x cap to provide operational flexibility in the event of gas curtailments.

Specific Condition No. 4 - The required operating rate during the compliance test was modified to reflect the maximum capacity achievable at a given ambient temperature.

Specific Condition No. 7 - Language was added to clarify that a revised BACT analysis is dependent on the facility meeting the emission limits.

The final action of the Department will be to issue construction permit AC 01-204652 (PSD-FL-181) as modified.

Florida Department of Environmental Regulation
Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400
Lawton Chiles, Governor
Carol M. Browner, Secretary

PERMITTEE:
Florida Power Corporation
3201 - 34th Street South
St. Petersburg, FL 33733

Permit Number: AC 01-204652
PSD-FL-181
Expiration Date: December 31, 1994
County: Alachua
Latitude/Longitude: 29°38'23"N
82°20'55"W
Project: UF Cogeneration Facility

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-2 and 17-4. 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 and made a part hereof and specifically described as follows:

For the construction of a 43 Megawatt cogeneration facility consisting of replacement of existing boiler Nos. 1, 2, and 3 with a GE LM-6000 combustion turbine in series with a duct burner at a designed flow of 325,200 ACFM, and operating existing boiler Nos. 4 and 5 as auxiliary units.

Particulate emissions shall be controlled by using clean fuels and good combustion practices. CO emissions shall be initially controlled by proper combustion techniques. NO_X emissions shall be initially controlled by steam injection. Future control requirements for CO and NOx will be established by a revised BACT determination if deemed necessary by the Department.

The facility is located at the existing Central Heat Plant on the campus of the University of Florida in Gainseville, Alachua County, Florida. The UTM coordinates are 369.4 km East and 3,279.3 km North.

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

<u>Attachments are listed below:</u>

1. FPC letter dated 11-13-91.
2. FPC letter dated 11-25-91.
3. KBN letter dated 12-2-91.
4. DER incompleteness letter dated 12-31-91.
5. FPC letter dated 1-2-92.
6. EPA letter dated 1-8-92.
7. DER letter to EPA dated 1-16-92.

Attachments Cont'd

8. KBN letter dated 1-30-92.
9. FPC letter to EPA dated 2-6-92.
10. DER letter to EPA dated 2-12-92.
11. DER letter to EPA dated 2-14-92.
12. FPC response to incompleteness dated 3-5-92.
13. FWS letter to DER dated 4-2-92.
14. EPA letter to DER dated 4-8-92.
15. KBN letter to DER dated 4-8-92.
16. EPA letter to DER dated 6-16-92.
17. FPC letter to DER dated 6-19-92.
18. FPC letter to DER dated 7-29-92.

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, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

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), Florida Statutes, 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.

GENERAL CONDITIONS:

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

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 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

GENERAL CONDITIONS:

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 Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. 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 Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-30.300, F.A.C., as applicable. 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)

GENERAL CONDITIONS:

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 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:

1. Unless otherwise indicated, the construction and operation of the subject cogeneration facility shall be in accordance with the capacities and specifications stated in the application.

PERMITTEE:
Florida Power Corporation

Permit Number: AC 01-204652
PSD-FL-181
Expiration Date: December 31, 1994

SPECIFIC CONDITIONS:

2. Emissions from this facility shall not exceed the limits listed below:

Pollutant	Source	Fuel	Basis of Limit	lbs/hr	tons/yr
NOx	Turbine	Gas	EBM*:25 ppmvd @ 15% O2	35.0	142.7
	Turbine	Oil	EBM*:42 ppmvd @ 15% O2	66.3	7.3
	D.Burner	Gas	EBM*:0.1 lb/MMBTU	18.7	24.6
SO2	Turbine	Oil	BACT:0.5% Sulfur Max.	-	-
	Boiler 4	Oil	BACT:0.5% Sulfur Max.	-	-
	Boiler 5	Oil	BACT:0.5% Sulfur Max.	-	-
VE	Turbine	Gas/Oil	Equivalent of mass EBM*	10%/20% opacity**	
	D.Burner	Gas	" " "	10% opacity	
	Boiler 4	Gas/Oil	" " "	10%/20% opacity**	
	Boiler 5	Gas/Oil	" " "	10%/20% opacity**	
CO	Turbine	Gas	BACT:42 ppmvd	38.8	158.0
	Turbine	Oil	EBA***:75 ppmvd	70.5	7.7
	D.Burner	Gas	BACT:0.15 lb/MMBTU****	28.1	36.9

*EBM: Established by manufacturer
**Except for one 6-minute period per hour of not more than 27% opacity
***EBA: Established by applicant
****BACT limit proposed by applicant in Table A-2 of application

3. Fuel consumption rates and hours of operation for the turbine and duct burner shall not exceed those listed below:

	Natural Gas			No. 2 Fuel Oil		
	M ft3/hr*	MM ft3/yr	hrs/yr*	M gal/hr*	M gal/yr	hrs/yr*
Turbine	367.9	2997.2**	8146.8**	2.9	635.1	219.0**
Duct Burner	197.7	519.5	2628.0	0	0	0

*Based on maximum firing rates. Units may run at lower rates for more hours within annual fuel limits.

**An additional 1.9 hours/yr operation on natural gas will be allowed for each 1.0 hour/yr that fuel oil is not burned (up to 219 x 1.9 hours/yr), in which case, the emission limits in Specific Condition No. 2 shall be adjusted accordingly.

SPECIFIC CONDITIONS:

Boilers Nos. 4 and 5, firing natural gas or No. 2 fuel oil, may be operated as necessary for backup, as long as total NO_x emissions from the four sources within the permitted facility do not exceed 194.3 tons NO_x per year. The permittee shall maintain the required fuel use records to demonstrate compliance with this condition and include the total NO_x emission calculation in each annual operating report.

4. Before this construction permit expires, the cogeneration facility and Central Heat Plant (Boilers 4 and 5) stacks shall be sampled or tested as applicable according to the emission limits in Specific Condition No. 2. Annual compliance tests shall be conducted each year thereafter. Compliance tests shall be run at 96% to 100% of the maximum capacity achievable for the average ambient temperature during the compliance tests. The turbine manufacturer's capacity vs. temperature (ambient) curve shall be included with the compliance test results. Tests shall be conducted using the following reference methods:

NO_x: EPA Method 20
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9
CO: EPA Method 10

5. The DER Northeast District office shall be notified at least 30 days prior to the compliance tests. Compliance test results shall be submitted to the DER Northeast District office and the Bureau of Air Regulation office within 45 days after completion of the tests. Sampling facilities, methods, and reporting shall be in accordance with F.A.C. Rule 17-2.700 and 40 CFR 60, Appendix A.

6. A continuous operations monitoring system shall be installed, operated, and maintained in accordance with 40 CFR 60.334. The natural gas, fuel oil and steam injection flows to the cogeneration turbine along with the power output of the generator shall be metered and continuously recorded. The data shall be logged daily and maintained so that it can be provided to DER upon request.

7. The permittee shall have the option of including, in the initial construction, adequate modules and other provisions necessary for future installation of state-of-the-art catalytic abatement or equivalent CO and NOx control systems. Within 90 days of receipt of the initial compliance test results, the Department shall, if CO emission limits are not met, review the need for making a revised determination of Best Available Control Technology for CO.

SPECIFIC CONDITIONS:

If test results from the turbine and duct burner show that it is unlikely that NO_x limits can be met, a revised BACT determination for NO_x shall also be considered. The Department may revise the BACT determination to require installation of such technology if so indicated by the revised BACT cost/benefit analysis. If the permittee has elected not to provide for future addition of such technology in the initial construction and later applies for a permit modification to increase capacity, the retrofit costs associated with not making provisions for such technology (initially) shall not be considered by the Department in the retrofit cost analysis required for the future expansion.

8. Boilers Nos. 1, 2 and 3 shall permanently cease operation upon receipt of the operation permit for the cogeneration facility.

9. 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).

10. 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).

Issued this ______ day
of ________________, 1992

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

____
Carol M. Browner, Secretary

Revised
Best Available Control Technology (BACT) Determination
University of Florida Cogeneration Project
Alachua County

The applicant proposes to install a 43 MW cogeneration facility to replace existing boiler capacity at the University of Florida - Gainesville campus in Alachua County. The facility will consist of a General Electric LM-6000 Gas Turbine Generator exhausting through a duct-fired heat recovery steam generator which will produce steam for the University campus. The turbine and duct burner will be fired by natural gas with No. 2 fuel oil being used only as a backup fuel for the turbine.

A BACT determination is required for all regulated air pollutants emitted in amounts equal to or greater than the significant emission rates listed in Table 500-2 of Florida Administrative Code (F.A.C.) Rule 17-2.500.

The following table presents the estimated actual emissions in tons per year proposed by the applicant for NO_x, SO_2, PM/PM_{10}, VOC, and H_2SO_4. The Department accepts the applicant's proposed emissions for those pollutants, but will require a more stringent CO limit for the turbine during natural gas firing than proposed by the applicant (42 ppmvd vs. 75 ppmvd).

	Gas Turbine		Duct Burner	Total	Offsets	Increase	PSD
	NG	Oil	NG				
NO_x	142.7	7.3	24.6	174.6	134.9	39.7	40.0
SO_2	4.3	21.6	0.7	26.6	36.1	-9.5	40.0
PM/PM_{10}	10.2	1.1	2.5	13.8	3.4	10.4	25/15
CO	158.0	7.7	36.9	202.6	20.4	182.2	100.0
VOC	6.5	0.4	10.6	17.5	1.1	16.4	40.0
H_2SO_4	0.3	2.0	0.1	2.4	0.8	1.6	7.0

Emissions are based on firing natural gas in the turbine for 8,147 hours/yr at 348 MMBTU/hr and natural gas in the duct burner for 2,628 hours/yr at 187 MMBTU/hr. Oil firing in the turbine is based on 219 hours/yr at 382.6 MMBTU/hr.

Turbine performance under natural gas firing is based on NO_x emissions of 25 ppmvd (corrected to 15 percent O2). Performance on oil firing is based on NO_x emissions of 42 ppmvd (corrected to 15 percent O2). SO_2 emissions are based on 0.5 percent sulfur.

Date of Receipt of a Complete Application

March 6, 1992

BACT Determination Requested by Applicant

Control Technology: Combustion efficiency for cogeneration CO control.

Emission Limits: 75 ppmvd CO (natural gas or No. 2 oil - 0.5% Sulfur max.)
(No request made for Boilers 4 and 5)

BACT Determined by the Department

Control Technology: Combustion efficiency for cogeneration CO control.

Emission Limits:	Turbine - Natural gas firing:	42 ppmvd CO
	Turbine - No. 2 oil firing:	75 ppmvd CO
	Maximum % Sulfur - No. 2 oil:	0.5 % S
	Duct Burner - Natural gas:	0.15 lb CO/MMBTU
	Boilers 4 & 5: (Gas/Oil)	10%/20% Opacity

BACT Determination Procedure

In accordance with F.A.C. Chapter 17-2, 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 control methods, systems and techniques. In addition, the regulations require 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 determinations 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.

A review of EPA's BACT/LAER Clearinghouse indicates that catalytic oxidation is the most stringent control technique. An oxidation catalyst control system allows unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F and reaches near completion (above 90%) at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than for thermal oxidation thus reducing the thermal energy required. The oxidation catalyst is typically located directly after the turbine or as an integral part of the steam generator. Catalyst size depends on the exhaust flow, temperature, and desired efficiency.

Catalytic oxidation for CO control has been employed in nonattainment areas and is considered to be LAER technology capable of reducing CO emissions to the 10 ppm range. Due to economics, applications of catalytic oxidation technology have thus far been limited to small cogeneration facilities burning natural gas. Oxidation catalysts have not been used on base-loaded fuel oil-fired turbines in simple cycle or combined cycle facilities since extended use of sulfur-containing fuel would result in increased corrosion. Also, trace metals in the fuel could poison catalysts during prolonged fuel oil firing.

Using the applicant's proposed CO emission level of 75 ppmvd, the total annualized cost of CO catalytic oxidation for this project is $508,156 with a cost effectiveness of about $1,970/ton of CO removed. The cost effectiveness is based on 87% efficiency (75 ppmvd to 10 ppmvd) and includes a heat rate penalty of 0.2% based on an energy loss of $50/MW associated with pressure drop across the catalyst. A review of previous BACT determinations indicates that $1,970/ton would not be prohibitive. However, the decision to require catalytic oxidation should be based on a cost/benefit analysis once compliance testing has been done. Therefore, the Department will propose initial BACT emission limits for CO consistent with recent BACT determinations for similar sources. These limits are to be revised, if necessary, upon evaluation of the compliance test data. The turbine limit proposed by the applicant for fuel oil operation (75 ppmvd) is more stringent than a recent BACT determination for similar sources (78 ppmvd).

Other Air Pollutants Not Subject to BACT Determination

The application indicates that emissions of other pollutants will not be subject to a BACT determination. The applicant narrowly escaped PSD review for NO_x by lowering firing rates, and since increased firing rates may be requested at some future date, the Department will require that retrofit costs associated with the applicant's decision not to make initial provisions for future installation of advanced catalytic control shall not be considered in any cost analysis required for any future requested increase in capacity.

Details of the Analysis May be Obtained by Contacting:

Preston Lewis, P.E., BACT Coordinator
Department of Environmental Regulation
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	Carol M. Browner, Secretary Dept. of Environmental Regulation
______________1992 Date	______________1992 Date

9:45

Clair,

This is the completed Settlement Stipulation for Florida Power. The original is in OGC. Everything appears ready to go. Thanks

Jeff Bracewell

Patty

8/18

For permit file

Clair

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

REGION IV

345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

RECEIVED
AUG 17 1992
Division of Air
Resources Management

4APT-AEB

AUG 11 1992

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

RE: Florida Power Corp. - U of F Project (PSD-FL-181)

Dear Mr. Fancy:

This is to acknowledge receipt of your revised preliminary determination and draft Prevention of Significant Deterioration (PSD) permit for the above referenced facility by letter dated June 30, 1992. The proposed modification involves the shutdown of three existing boilers and the construction of a combined cycle combustion turbine (GE LM 6000 model). As a result of the shutdowns, the modification will have a significant increase in emissions for CO only.

The revisions to the preliminary determination consisted of increasing the allowable fuel oil sulfur content to 0.5%; applying the new source performance standard opacity limit; increasing the duct burner CO limit to 0.15 lb/mmBTU; allowing for operation of the existing boilers until the operating permit for the new facility is obtained; and, modifying the permit language concerning the construction of duct modules for future installation of NO_x and/or CO controls.

We have reviewed the package as requested and have no adverse comments. If you have any questions or comments on this project, please contact Mr. Gregg Worley of my staff at (404) 347-5014.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

cc: J. Reynolds
C. Holladay, NE Dist.
A. Kutyna,
C. Shaver, NPS
K. Kosky, P.E.

Printed on Recycled Paper

Florida Power
CORPORATION

Certified Mail
P 164 730 333

July 31, 1992

Mr. C. H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Mr. Fancy:

Re: Proof of Publication of the Notice of Intent to Issue the UF Cogeneration Project Construction Air Permit

Pursuant to Section 403.315, Florida Statutes and DER Rule 17-103.150, F.A.C., the Notice of Intent to issue the UF Cogeneration Project Construction Air Permit was published July 3, 1992 in the Gainesville Sun. Enclosed is proof of this publication.

If you have any questions or require any additional information, please contact me at (813) 866-5158.

Sincerely,

Scott H. Osbourn
Senior Environmental Engineer

Enclosure

№ 3269

THE GAINESVILLE SUN
Published Daily and Sunday
GAINESVILLE, FLORIDA

STATE OF FLORIDA
COUNTY OF ALACHUA

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

who on oath says that he/she is ..Assistant...Classified...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,.

..........................July...3... 19....92..........

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

10 day of July A.D., 1992

Bonnie W. Gragg

(Seal) Notary Public

NOTARY PUBLIC STATE OF FLORIDA

BONNIE W. GRAGG
My Comm. Exp. S...
Bonded By S...

Naomi Williams

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

The Department of Environmental Regulation gives notice of its intent to issue a permit to Florida Power Corporation, 3201 - 34th Street South, St. Petersburg, Florida 33733, to construct a 43 MW cogeneration facility on Mowry Road at the University of Florida campus in Gainesville, Alachua County, Florida. A determination of Best Available Control Technology (BACT) was required. The proposed project is subject to Prevention of Significant Deterioration (PSD) regulations in regard to carbon monoxide emissions and federal new source performance standards for nitrogen oxides. Modeling results show that increases in ground-level concentrations are less than PSD significant impact levels for carbon monoxide. 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. 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, Florida Statutes.

The Petition shall contain the following information: (1) The name, address, and telephone number of each petitioner, the applicant's name and address, the Department permit File Number and the country 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, F.A.C.

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 Regulation, Bureau of Air Regulation, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.
Department of Environmental Regulation, Northeast District, 7825 Baymeadows Way, Suite B200, Jacksonville, Florida 32256-7577.

Any person may send written comments on the proposed action to Mr. Preston Lewis 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. Such requests must be submitted within 30 days of this notice.
(3690) 7-3 3269

Florida Power
CORPORATION

3201 THIRTY FOURTH STREET SOUTH • ST. PETERSBURG, FLORIDA 33711
P.O. BOX 14042 - H2G • ST. PETERSBURG, FLORIDA 33733

FAX COVER LETTER

ENVIRONMENTAL SERVICES DEPARTMENT

DATE: 7/30/92

TO: Preston Lewis
Air Permitting

FROM: ~~Scott~~ Osborn

7 PAGES AND COVER SHEET

FAX #: (904) 922-6979

PHONE #: (813) 866-5158

PROJECT NUMBER:

PLEASE NOTIFY (813) 866-4940 FOR ANY PROBLEMS CONCERNING THE RECEIPT OF THIS FAX.

RECEIVED
JUL 30 1992
Division of Air
Resources Management

~~Clair~~ / Patty
This is Univ FL and I asked
John R to comment on this
Preston
7/30/92

Florida Power CORPORATION

July 29, 1992

Mr. C. H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Rd.
Tallahasse, Florida 32399-2400

Subject: Alachua County- A.P.
UF Cogeneration Project
AC 01-204650, PSD-FL-181

Dear Mr. Fancy:

This correspondence provides comments to the revised draft air construction permit for the University of Florida (UF) Cogeneration Project. These comments are a follow-up to discussions with Messrs. Preston Lewis and John Reynolds of your staff. The comments are focused on certain specific conditions and are listed below. Requested changes to the conditions are attached.

Specific Condition 3. The fuel usage for Boiler Nos. 4 and 5 is not consistent with the information supplied to the Department on March 5, 1992, and again restated in our June 19, 1992 submittal. Specifically, the proposed fuel usage and supporting documentation are contained in the March 5, 1992 submittal, Table 2-5:

Boiler No. 4 -- Natural gas (20 MMcf/yr) and no. 2 fuel oil (15,000 gal/yr)
Boiler No. 5 -- Natural gas (125 MMcf/yr) and no. 2 fuel oil (50,000 gal/yr)

These fuel usage rates were developed based on the same assumptions for which the Department offsets were calculated . The Department accepted the offsets submitted in the application as stated on Page 3 of the Technical Evaluation and Preliminary Determination. It should be noted that the NO_x emissions in revised Table 2-5 were based on the same emission factor as that used for the offsets. This assumption is consistent with the overall approach recommended by the Department.

In addition, the issue of operational flexibility is one of great importance to FPC. As stressed in separate conversations with John Reynolds and Preston Lewis, such flexibility is essential during natural gas curtailments or an unscheduled long-term maintenance shutdown. (During such time, the backup boilers would be required to supply hospital process steam.) Our June 19, 1992 letter contained recommended footnotes to the fuel usage table previously discussed above. The proposed footnotes would allow fuel oil and natural gas usage trade-offs between the combustion turbine (CT) and back-up boilers (e.g., fuel oil for fuel oil and natural gas for natural gas) structured to restrict trade-offs in such a way that overall NO_x emissions would not be increased.

Neither Messrs. Lewis nor Reynolds are opposed to providing the requested flexibility; however, there seems to be some confusion regarding the most effective method of implementation. Therefore, FPC proposes the following two different approaches:

The first approach is the same as that contained in our June 19, 1992 submittal and is reiterated below:

- The usage of oil for boilers 4 and 5 may be increased by 0.96 gallons of oil for every gallon not burned in the turbine. The total amount of oil to be used in the turbine will be reduced by this amount.

- The usage of natural gas for boilers 4 and 5 may be increased by 0.34 cubic feet for every cubic foot not burned in the turbine. The total amount of natural gas to be used in the turbine will be reduced by this amount.

The proposed ratios for trade-off are based on the limiting pollutant, NO_x , so that overall NO_x emissions would not be increased.

The second approach is less complex and involves implementing the total NO_x cap. The condition could be written such that "total NO_x emissions from the four sources (the CT, duct burner, boiler 4 and boiler 5) shall not exceed 194.3 tons per year (174.6 tpy from the CT and duct burner and 19.73 tpy from boilers 4 and 5). FPC shall maintain annual fuel use records and apply appropriate emission factors (or sorce test data, if available) to calculate and submit annual emission estimates." This approach is consistent with current Department practice which requires submittal of annual operating and emissions reports.

Specific Condition 4. As stated in our June 19, 1992 letter, the requirement to test between 96 and 100 percent of capacity does not appear to be consistent with previous permit conditions issued by the Department. Also, low ambient temperatures are required for the maximum capacity to be achieved in the CT. This ambient temperature dependence of the

CT and a minimum 96 percent requirement for testing of the CT would make it all but certain that this condition could not be met. Therefore, the required range for testing should be 90 to 100 percent of maximum permitted capacity.

Initially, the CT will only be equipped to burn natural gas. FPC realizes that compliance testing is ncessary on all fuels proposed for firing and, therefore, will not burn fuel oil in the CT unless and until compliance with the Department's emission limits is demonstrated.

In addition, as previously discussed, the stack sampling requirements for the Central Heat Plant (Boilers 4 and 5) should be deleted from this condition. There are no emission limits in Specific Condition 2 for these units.

Specific Condition 7. The phrase "for CO." should be added after the second sentence since a BACT review was not performed for NO_x . Further, FPC believes that the decision to require a CO oxidation catalyst will be based on a cost/benefit analysis of using such control only if compliance testing indicates that FPC is unable to meet the CO limits established in Table 2.

The Department's expeditious consideration of these comments is appreciated. As you know, this is an important project to the University of Florida and will have significant environmental benefits over the existing steam generating system. This project will reduce potential emissions from the facility by over 800 tons per year while saving the University of Florida over $2,000,000 annually.

If you should have any questions or require clarification of the above, please do not hesitate to contact me at (813) 866-5158.

Sincerely,

Scott H. Osbourn
Senoir Environmental Engineer

cc: Preston Lewis, FDER
John Reynolds, FDER
Jeff Braswell, OGC/FDER

Table 2-5. Emissions of Regulated Pollutants for Boilers 4 & 5 After Commercial Operation of Cogeneration Plant (Page 1 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 2 Fuel Oil	Natural Gas	No. 2 Fuel Oil	Total
Natural Gas Burned[c] (MM ft^3/yr)	20		125		
No. 2 Fuel Oil[c] (gal/yr)		15,000		50,000	
(% sulfur)		0.5		0.5	
Emission Factor	lb/MM scf	lb/1,000 gal	lb/MM scf	lb/1,000 gal	
Particulate Matter	3	8[d]	3	8[d]	
Particulate Matter (PM10)	3	5.68[d]	3	5.68[d]	
Sulfur Dioxide	0.6	78.5[e]	0.6	78.5[e]	
Nitrogen Oxides	140	20	281.2	24	
Carbon Monoxide	35	5	40	5	
Volatile Organic Compounds (methane)	3	0.052	0.3	0.052	
Volatile Organic Compounds (nonmethane)	2.8	0.2	1.4	0.2	
Lead	Neg.	0.0013	Neg.	0.0042	
Fluorides	Neg.	0.0049	Neg.	0.052	
Mercury	Neg.	0.00045	Neg.	0.00048	
Beryllium	Neg.	0.00038	Neg.	0.00063	
Arsenic	Neg.	0.00063	Neg.	0.0029	
Sulfuric Acid Mist	Neg.	1.225	Neg.	1.225	
Emission Rate (TPY)					
Particulate Matter	0.03	0.06	0.19	0.20	0.48
Particulate Matter (PM10)	0.03	0.04	0.19	0.14	0.40
Sulfur Dioxide	0.01	0.59	0.04	1.96	2.59
Nitrogen Oxides	1.40	0.15	17.58	0.61[f]	19.73
Carbon Monoxide	0.35	0.04	2.50	0.13	3.01
Volatile Organic Compounds (methane)	0.03	0.00	0.02	0.00	0.05
Volatile Organic Compounds (nonmethane)	0.03	0.00	0.09	0.01	0.12

Fuel use as accepted in technical evaluation

91062C2/ADNDM
03/04/92

Table 2-5. Emissions of Regulated Pollutants for Boilers 4 & 5 After Commercial Operation of Cogeneration Plant (Page 2 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 2 Fuel Oil	Natural Gas	No. 2 Fuel Oil	Total
Lead	Neg.	0.00001	Neg.	0.00011	0.0001
Fluorides	Neg.	0.00004	Neg.	0.00130	0.001
Mercury	Neg.	0.00000	0.0000	0.00001	0.00000
Beryllium	Neg.	0.00000	Neg.	0.00002	0.00002
Arsenic	Neg.	0.00000	Neg.	0.00007	0.0001
Sulfuric Acid Mist	Neg.	0.01	Neg.	0.03	0.04

Note: Calculations in this table are performed as follows: Fuel use times emission factor equals emission rate; e.g. 20 MM scf/yr x 3 lb/MM scf + 2,000 lb/ton = 0.03 TPY (Note: Roundoff from Lotus may slightly different than calculations using a calculator.).

ft^3/yr = cubic feet per year
gal/yr = gallons per year
% = percent
lb/mm = pounds per millimeter
scf = standard cubic feet
gal = gallons
Btu/hr = British thermal unit per hour
PM = particulate matter
PM10 = particulate matter (PM10)
TPY = tons per year

[a] Boiler 4 has a heat input capacity of less than 100 x 10^6 Btu/hr; therefore, emissions factors for industrial boilers were used.
[b] Boiler 5 has a heat input capacity of greater than 100 x 10^6 Btu/hr; therefore, emission factors for utility boilers were used.
[c] Based on annual operating reports (See Appendix A).
[d] Based on equation: 10 S + 3, where S = sulfur content. PM10 is 71% of PM emissions.
[e] Based on equation: 157 S, where S = sulfur content.
[f] Nitrogen oxides emissions based on ratio of residual and distillate oil emission factors [67 lb/10^3 gallons x 20 lb/10^3 gallons (for distillate) ÷ 55 lb/10^3 gallons (for residual)].

Table 2-6. Net Emission Reductions From Boilers 1 Through 5 at UF Central Heating Plant

Pollutant	Net Emission Reduction (TPY)		
	Boilers[a] 1, 2 and 3	Boilers[b] 4 and 5	Total
Particulate Matter	-1.00	-3.13	-4.13
Particulate Matter (PM10)	-0.96	-2.42	-3.38
Sulfur Dioxide	-1.99	-34.08	-36.07
Nitrogen Oxides	-72.18	-62.69	-134.87
Carbon Monoxide	-11.04	-9.38	-20.41
Volatile Organic Compounds (methane)	-0.37	-0.31	-0.67
Volatile Organic Compounds (nonmethane)	-0.55	-0.49	-1.05
Lead	-0.0000	-0.0004	-0.0004
Fluorides	-0.0003	-0.0051	-0.0054
Mercury	-0.00000	-0.00	-0.00
Beryllium	-0.00000	-0.00006	-0.00006
Arsenic	-0.0000	-0.0003	-0.0003
Sulfuric Acid Mist	-0.0411	-0.7366	-0.7777

These offsets accepted by Dept. and were based on Table 2-5

Note: TPY = tons per year.

[a]Based on emissions in Table 2-3.
[b]Based on subtracting emissions in Table 2-4 from emissions in Table 2-5.

two year period is more representative of normal operation. This is summarized in the following excerpt from EPA's 1991 workshop document on creditable emission changes:

> "In certain limited situations where the applicant adequately demonstrates that the prior two years is not representative of normal source operation, a different two year time period may be used upon a determination by the reviewing agency that it is more representative of normal source operation." (emphasis added)

Therefore, since EPA requires that any alternate representative period be no more than two years, 1989 and 1991 would be the proper two years on which to base actual emissions for this project. As it turns out, the applicant's proposed offsets based on ~~1988 through 1990 are within 1% of the 1989/1991 average,~~ therefore the Department can use the applicant's offset estimates. The increased ~~emissions from this project~~ are:

OFFSETS BASED ON FUEL USE IN Table 2-5.

Allowable Emissions (TPY)

	Gas Turbine NG	Gas Turbine Oil	Duct Burner NG	Total	Offsets	Net Increase
NO_x	142.7	7.3	24.6	174.6	134.9	39.7
SO_2	4.3	21.6*	0.7	26.6*	36.1	- 9.5*
PM/PM_{10}	10.2	1.1	2.5	13.8	3.4	10.4
CO	158.0	7.7	36.9	202.6	20.4	182.2
VOC	6.5	0.4	10.6	17.5	1.1	16.4
H_2SO_4	0.3	2.0	0.1	2.4	0.8	1.6

* Estimate based on 0.5% fuel sulfur content

III. Rule Applicability

The construction permit application is subject to review under Chapter 403, Florida Statutes, and Florida Administrative Code (F.A.C.) Chapters 17-2 and 17-4. The proposed facility is subject to the provisions of F.A.C. Rule 17-2.500, Prevention of Significant Deterioration (PSD). The facility is located in an area classified as attainment for all regulated air pollutants. The proposed increase in carbon monoxide (CO) emissions exceeds the significant level set forth in Table 500-2 of F.A.C. Rule 17-2.500. Preconstruction review must include a determination of Best Available Control Technology (BACT), good-engineering practice stack height, ambient impact analysis, impact on soils, vegetation and visibility. Applicable emission limit rules are F.A.C. Rules 17-2.660, Table 660-1, Section 60.330, New Source Performance Standards for Stationary Gas Turbines, Subpart GG, and Section 60.40b, Subpart Db, Industrial/Commercial/Institutional Steam Generating Units. Limits for nitrogen oxides (NOx) and particulate matter (PM) emissions will be based on the turbine manufacturer's performance guarantees since they are more stringent than the NSPS

Florida Power
CORPORATION

RECEIVED
JUL 31 1992
Division of Air
Resources Management

July 29, 1992

Mr. C. H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Rd.
Tallahasse, Florida 32399-2400

Subject: Alachua County- A.P.
UF Cogeneration Project
AC 01-204650, PSD-FL-181

Dear Mr. Fancy:

This correspondence provides comments on the revised draft air construction permit for the University of Florida (UF) Cogeneration Project. These comments are a follow-up to discussions with Messrs. Preston Lewis and John Reynolds of your staff. The comments are focused on certain specific conditions and are listed below.

Specific Condition 3. The fuel usage for Boiler Nos. 4 and 5 is not consistent with the information supplied to the Department on March 5, 1992, and again restated in our June 19, 1992 submittal. Specifically, the proposed fuel usage and supporting documentation are contained in the March 5, 1992 submittal, Table 2-5 (attached):

Boiler No. 4 -- Natural gas (20 MMcf/yr) and no. 2 fuel oil (15,000 gal/yr)
Boiler No. 5 -- Natural gas (125 MMcf/yr) and no. 2 fuel oil (50,000 gal/yr)

These fuel usage rates were developed based on the same assumptions for which the Department offsets were calculated . The Department accepted the offsets submitted in the application as stated on Page 3 of the Technical Evaluation and Preliminary Determination (attached). It should be noted that the NO_x emissions in revised Table 2-5 were based on the same emission factor as that used for the offsets. This assumption is consistent with the overall approach recommended by the Department.

In addition, the issue of operational flexibility is one of great importance to FPC. As stressed in separate conversations with John Reynolds and Preston Lewis, such flexibility is essential during natural gas curtailments or an unscheduled long-term maintenance shutdown. (During such time, the backup boilers would be required to supply hospital process steam.) Our June 19, 1992 letter contained recommended footnotes to the fuel usage table previously discussed above. The proposed footnotes would allow fuel oil and natural gas usage trade-offs between the combustion turbine (CT) and back-up boilers (e.g., fuel oil for fuel oil and natural gas for natural gas) structured to restrict trade-offs in such a way that overall NO_x emissions would not be increased.

Neither Messrs. Lewis nor Reynolds are opposed to providing the requested flexibility; however, there seems to be some confusion regarding the most effective method of implementation. Therefore, FPC proposes the following two different approaches:

The first approach is the same as that contained in our June 19, 1992 submittal and is reiterated below:

- o The usage of oil for boilers 4 and 5 may be increased by 0.96 gallons of oil for every gallon not burned in the turbine. The total amount of oil to be used in the turbine will be reduced by this amount.

- o The usage of natural gas for boilers 4 and 5 may be increased by 0.34 cubic feet for every cubic foot not burned in the turbine. The total amount of natural gas to be used in the turbine will be reduced by this amount.

The proposed ratios for trade-off are based on the limiting pollutant, NO_x, so that overall NO_x emissions would not be increased.

The second approach is less complex and involves implementing the total NO_x cap. The condition could be written such that "total NO_x emissions from the four sources (the CT, duct burner, boiler 4 and boiler 5) shall not exceed 194.3 tons per year (174.6 tpy from the CT and duct burner and 19.73 tpy from boilers 4 and 5). FPC shall maintain annual fuel use records and apply appropriate emission factors (or source test data, if available) to calculate and submit annual emission estimates." This approach is consistent with current Department practice which requires submittal of annual operating and emissions reports.

Specific Condition 4. As stated in our June 19, 1992 letter, the requirement to test between 96 and 100 percent of capacity does not appear to be consistent with previous permit conditions issued by the Department. Also, low ambient temperatures are required for the maximum capacity to be achieved in the CT. This ambient temperature dependence of the CT and a minimum 96 percent requirement for testing of the CT would make it all but certain that this condition could not be met. Therefore, the required range for testing should be 90 to 100 percent of maximum permitted capacity.

Initially, the CT will only be equipped to burn natural gas. FPC realizes that compliance testing is necessary on all fuels proposed for firing and, therefore, will not burn fuel oil in the CT unless and until compliance with the Department's emission limits is demonstrated.

In addition, as previously discussed, the stack sampling requirements for the Central Heat Plant (Boilers 4 and 5) should be deleted from this condition. There are no emission limits in Specific Condition 2 for these units which would require stack sampling.

Specific Condition 7. The phrase "for CO." should be added after the second sentence since a BACT review was not performed for NO_x. Further, FPC believes that the decision to require a CO oxidation catalyst will be based on a cost/benefit analysis of using such control only if compliance testing indicates that FPC is unable to meet the CO limits established in Table 2. The current wording should be modified to make this requirement clear.

The Department's expeditious consideration of these comments is appreciated. As you know, this is an important project to the University of Florida and will have significant environmental benefits over the existing steam generating system. This project will reduce potential emissions from the facility by over 800 tons per year while saving the University of Florida over $2,000,000 annually.

If you should have any questions or require clarification of the above, please do not hesitate to contact me at (813) 866-5158.

Sincerely,

Scott H. Osbourn
Senoir Environmental Engineer

Enclosure

cc: Preston Lewis, FDER
John Reynolds, FDER
Jeff Braswell, OGC/FDER
A. Kutyna, NE Dist
G. Harper, EPA
C. Shaver, NPS

Table 2-5. Emissions of Regulated Pollutants for Boilers 4 & 5 After Commercial Operation of Cogeneration Plant (Page 1 of 2)

Fuel use as accepted in technical evaluation

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 2 Fuel Oil	Natural Gas	No. 2 Fuel Oil	Total
Natural Gas Burned[c]					
(MM ft^3/yr)	20		125		
No. 2 Fuel Oil[c]					
(gal/yr)		15,000		50,000	
(% sulfur)		0.5		0.5	
Emission Factor	lb/MM scf	lb/1,000 gal	lb/MM scf	lb/1,000 gal	
Particulate Matter	3	8[d]	3	8[d]	
Particulate Matter (PM10)	3	5.68[d]	3	5.68[d]	
Sulfur Dioxide	0.6	78.5[e]	0.6	78.5[e]	
Nitrogen Oxides	140	20	281.2	24	
Carbon Monoxide	35	5	40	5	
Volatile Organic Compounds (methane)	3	0.052	0.3	0.052	
Volatile Organic Compounds (nonmethane)	2.8	0.2	1.4	0.2	
Lead	Neg.	0.0013	Neg.	0.0042	
Fluorides	Neg.	0.0049	Neg.	0.052	
Mercury	Neg.	0.00045	Neg.	0.00048	
Beryllium	Neg.	0.00038	Neg.	0.00063	
Arsenic	Neg.	0.00063	Neg.	0.0029	
Sulfuric Acid Mist	Neg.	1.225	Neg.	1.225	
Emission Rate (TPY)					
Particulate Matter	0.03	0.06	0.19	0.20	0.48
Particulate Matter (PM10)	0.03	0.04	0.19	0.14	0.40
Sulfur Dioxide	0.01	0.59	0.04	1.96	2.59
Nitrogen Oxides	1.40	0.15	17.58	0.61[f]	19.73
Carbon Monoxide	0.35	0.04	2.50	0.13	3.01
Volatile Organic Compounds (methane)	0.03	0.00	0.02	0.00	0.05
Volatile Organic Compounds (nonmethane)	0.03	0.00	0.09	0.01	0.12

Table 2-5. Emissions of Regulated Pollutants for Boilers 4 & 5 After Commercial Operation of Cogeneration Plant (Page 2 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 2 Fuel Oil	Natural Gas	No. 2 Fuel Oil	Total
Lead	Neg.	0.00001	Neg.	0.00011	0.0001
Fluorides	Neg.	0.00004	Neg.	0.00130	0.001
Mercury	Neg.	0.00000	0.0000	0.00001	0.00000
Beryllium	Neg.	0.00000	Neg.	0.00002	0.00002
Arsenic	Neg.	0.00000	Neg.	0.00007	0.0001
Sulfuric Acid Mist	Neg.	0.01	Neg.	0.03	0.04

Note: Calculations in this table are performed as follows: Fuel use times emission factor equals emission rate; e.g. 20 MM scf/yr x 3 lb/MM scf ÷ 2,000 lb/ton = 0.03 TPY (Note: Roundoff from Lotus may slightly different than calculations using a calculator.).

ft^3/yr = cubic feet per year
gal/yr = gallons per year
% = percent
lb/mm = pounds per millimeter
scf = standard cubic feet
gal = gallons
Btu/hr = British thermal unit per hour
PM = particulate matter
PM10 = particulate matter (PM10)
TPY = tons per year

[a] Boiler 4 has a heat input capacity of less than 100×10^6 Btu/hr; therefore, emissions factors for industrial boilers were used.

[b] Boiler 5 has a heat input capacity of greater than 100×10^6 Btu/hr; therefore, emission factors for utility boilers were used.

[c] Based on annual operating reports (See Appendix A).

[d] Based on equation: 10 S + 3, where S = sulfur content. PM10 is 71% of PM emissions.

[e] Based on equation: 157 S, where S = sulfur content.

[f] Nitrogen oxides emissions based on ratio of residual and distillate oil emission factors [67 lb/10^3 gallons x 20 lb/10^3 gallons (for distillate) ÷ 55 lb/10^3 gallons (for residual)].

Table 2-6. Net Emission Reductions From Boilers 1 Through 5 at UF Central Heating Plant

Pollutant	Net Emission Reduction (TPY) Boilers[a] 1, 2 and 3	Boilers[b] 4 and 5	Total
Particulate Matter	-1.00	-3.13	-4.13
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Nitrogen Oxides	-72.18	-62.69	-134.87
Carbon Monoxide	-11.04	-9.38	-20.41
Volatile Organic Compounds (methane)	-0.37	-0.31	-0.67
Volatile Organic Compounds (nonmethane)	-0.55	-0.49	-1.05
Lead	-0.0000	-0.0004	-0.0004
Fluorides	-0.0003	-0.0051	-0.0054
Mercury	-0.00000	-0.00	-0.00
Beryllium	-0.00000	-0.00006	-0.00006
Arsenic	-0.0000	-0.0003	-0.0003
Sulfuric Acid Mist	-0.0411	-0.7366	-0.7777

These offsets accepted by Dept. and were based on Table 2-5

Note: TPY = tons per year.

[a]Based on emissions in Table 2-3.
[b]Based on subtracting emissions in Table 2-4 from emissions in Table 2-5.

two year period is more representative of normal operation. This is summarized in the following excerpt from EPA's 1991 workshop document on creditable emission changes:

> "In certain limited situations where the applicant adequately demonstrates that the prior two years is not representative of normal source operation, a different two year time period may be used upon a determination by the reviewing agency that it is more representative of normal source operation." (emphasis added)

Therefore, since EPA requires that any alternate representative period be no more than two years, 1989 and 1991 would be the proper two years on which to base actual emissions for this project. As it turns out, the applicant's proposed offsets based on 1988 through 1990 are within 1% of the 1989/1991 average, therefore the Department can use the applicant's offset estimates. The increased emissions from this project are:

OFFSETS BASED ON FUEL USE IN Table 2-5.

Allowable Emissions (TPY)

	Gas Turbine NG	Gas Turbine Oil	Duct Burner NG	Total	Offsets	Net Increase
NO_x	142.7	7.3	24.6	174.6	134.9	39.7
SO_2	4.3	21.6*	0.7	26.6*	36.1	- 9.5*
PM/PM_{10}	10.2	1.1	2.5	13.8	3.4	10.4
CO	158.0	7.7	36.9	202.6	20.4	182.2
VOC	6.5	0.4	10.6	17.5	1.1	16.4
H_2SO_4	0.3	2.0	0.1	2.4	0.8	1.6

* Estimate based on 0.5% fuel sulfur content

III. Rule Applicability

The construction permit application is subject to review under Chapter 403, Florida Statutes, and Florida Administrative Code (F.A.C.) Chapters 17-2 and 17-4. The proposed facility is subject to the provisions of F.A.C. Rule 17-2.500, Prevention of Significant Deterioration (PSD). The facility is located in an area classified as attainment for all regulated air pollutants. The proposed increase in carbon monoxide (CO) emissions exceeds the significant level set forth in Table 500-2 of F.A.C. Rule 17-2.500. Preconstruction review must include a determination of Best Available Control Technology (BACT), good-engineering practice stack height, ambient impact analysis, impact on soils, vegetation and visibility. Applicable emission limit rules are F.A.C. Rules 17-2.660, Table 660-1, Section 60.330, New Source Performance Standards for Stationary Gas Turbines, Subpart GG, and Section 60.40b, Subpart Db, Industrial/Commercial/Institutional Steam Generating Units. Limits for nitrogen oxides (NOx) and particulate matter (PM) emissions will be based on the turbine manufacturer's performance guarantees since they are more stringent than the NSPS

Florida Power
CORPORATION

RECEIVED
JUL 29 1992
Division of Air
Resources Management

July 24, 1992

Mr. Jeff Braswell, Esq.
Office of General Counsel
Florida Department of Environmental Regulation
2600 Blairstone Road
Tallahassee, FL 32399-2400

Dear Mr. Braswell:

Re: Florida Power Corporation/University
of Florida Cogeneration Project
Permit No. AC 01-204652, PSD-FL-181

On June 8, 1992, Florida Power Corporation (FPC) received the Technical Evaluation and Preliminary Determination and proposed air construction permit for the above referenced facility. Because of unresolved issues at the time, an extension to July 24, 1992 in which to file a petition for an administrative hearing was subsequently granted. As of today, based on a conversation with Mr. Preston Lewis of FDER, unresolved issues still remain. Therefore, pursuant to Section 17-120.070, FAC, FPC respectfully requests an additional extension of time in which to file a petition for an administrative hearing under Section 120.57 FS, up to and including August 24, 1992.

Thank you for your consideration of this request. Please contact Mr. Scott Osbourn at (813)866-5158 if you have any questions.

Sincerely,

W. Jeffrey Pardue, Manager
Environmental Programs

cc: C. Fancy, FDER-Tallahassee

Florida Power
CORPORATION

Richard W. Neiser
Senior Vice President
Legal and
Governmental Affairs

May 29, 1992

TO WHOM IT MAY CONCERN

Subject: Letter of Authorization

Please be advised that Patricia K. Blizzard, Director, Environmental Services Department, and Mr. W. Jeffrey Pardue, Manager of Environmental Programs, are authorized to represent Florida Power Corporation in matters relating to necessary permits and reporting documentation required from regulatory authorities in the areas of air, water, power plant site certifications and transmission line certifications, or hazardous and solid materials issues.

Sincerely,

Richard W. Neiser

Richard W. Neiser

RWN:bb

Kofax

Separator

PSD

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

June 30, 1992

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. R. W. Neiser
Senior Vice President-Legal and Gov. Affairs
Florida Power Corporation
3201-34th Street South
St. Petersburg, Florida 33733

Dear Mr. Neiser:

Attached is one copy of the Revised Technical Evaluation and Preliminary Determination and proposed permit for Florida Power Corporation to construct a cogeneration facility at the University of Florida in Gainesville.

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

Sincerely,

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

CHF/JR/plm

Attachments

c: A. Kutyna, NED
J. Harper, EPA
C. Shaver, NPS
K. Kosky, KBN

P 710 058 543

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

UNITED STATES POSTAL SERVICE

Sent to Mr. R. W. Neiser, FPC	
Street & No. 3201-34th Street South	
P.O., State & ZIP Code St. Petersburg, FL 33733	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 7-6-92 Permit: AC 01-204652 PSD-FL-181	

PS Form 3800, June 1990

inTent

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 next to the article number.

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. R. W. Neiser
Sr. Vice President-Legal and
Gov. Affairs
Florida Power Corporation
3201-34th Street South
St. Petersburg, FL 33733

4a. Article Number
P 710 058 543

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

7. Date of Delivery JUL 8 1992

5. Signature (Addressee)

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

6. Signature (Agent)
Frank Chum

PS Form 3811, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

CERTIFIED MAIL

In the Matter of an
Application for Permit by:

DER File No. AC 01-204652
PSD-FL-181

Florida Power Corporation
3201-34th Street South
St. Petersburg, Florida 33733
_____________________________/

INTENT TO ISSUE

The Department of Environmental Regulation 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, Florida Power Corporation, applied on March 6, 1992, to the Department of Environmental Regulation for a permit to construct a cogeneration facility at the University of Florida in Gainesville, Alachua County, Florida.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes and Florida Administrative Code (F.A.C.) Chapters 17-2 and 17-4. 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, Florida Statutes and Rule 17-103.150, 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. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permits. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed on the fourth page. 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, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 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, Florida Statutes.

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 REGULATION

C. H. Fancy
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 July 6, 1992 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 7/6/92
Clerk Date

Copies furnished to:
- A. Kutyna, NED
- J. Harper, EPA
- C. Shaver, NPS
- K. Kosky, KBN

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

The Department of Environmental Regulation gives notice of its intent to issue a permit to Florida Power Corporation, 3201 - 34th Street South, St. Petersburg, Florida 33733, to construct a cogeneration facility on Mowry Road at the University of Florida campus in Gainesville, Alachua County, Florida. A determination of Best Available Control Technology (BACT) is required. The proposed project is subject to Prevention of Significant Deterioration (PSD) regulations in regard to carbon monoxide emissions and federal new source performance standards for nitrogen oxides. Modeling results show that increases in ground-level concentrations are less than PSD significant impact levels for carbon monoxide. 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. 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, Florida Statutes.

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, F.A.C.

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

Department of Environmental Regulation
Northeast District
7825 Baymeadows Way, Suite B200
Jacksonville, Florida 32256-7577

Any person may send written comments on the proposed action to Mr. Preston Lewis 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. Such requests must be submitted within 30 days of this notice.

Revised
Technical Evaluation
and
Preliminary Determination

Florida Power Corporation/University
of Florida Cogeneration Project
Alachua County, Florida

Permit No. AC 01-204652
PSD-FL-181

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

June 30, 1992

I. Application Information

A. Applicant

Florida Power Corporation
3201 - 34th Street South
St. Petersburg, Florida 33733

B. Request

The Department received a complete application on March 6, 1992, for a permit to construct a 43 megawatt (MW) cogeneration facility at the existing University of Florida Central Heat Plant in Gainesville. On June 2, 1992, the Department notified the applicant of the proposed permit conditions. On June 15, 1992, the applicant filed a request for an extension of time to file a petition for an administrative hearing. A meeting was held with the applicant on June 17, 1992, during which the Department agreed to modify the BACT and certain permit conditions. The changes agreed to consisted of the following: increasing the allowable fuel oil sulfur content to 0.5%, applying federal new source performance standards for opacity, increasing the duct burner CO limit, providing for overlap in operation of the existing boilers until the operation permit for the new facility is obtained, and modifying permit language concerning installation of duct modules for future advanced NO_x and CO control.

C. Classification/Location

The subject facility (SIC Code 8221) is located on Mowry Road at the University of Florida Campus in Gainesville. Latitude and longitude are 29°38'23"N and 82°20'55"W, respectively. The UTM coordinates of the site are: 369.4 km E and 3,279.3 km N.

II. Project Description/Emissions

The applicant proposes to construct a 43 MW cogeneration facility to replace existing Boilers 1, 2, and 3 and part of the current capacity of Boilers 4 and 5. The University's power and steam requirements will be provided by a General Electric LM-6000 gas turbine generator exhausting into a heat recovery steam generator producing 112,500 lbs/hr steam for the UF campus. The cogeneration facility will be located next to the existing Heat Plant No. 2. Primary fuel for the cogeneration facility will be natural gas. Distillate fuel oil will be used for up to 219 hours/yr.

The following discussion concerns how emissions offsets were determined. Since fuel use at the subject facility was abnormally low in 1990, the applicant requested that offsets be based on a three year period (1988-1990). EPA regulations require offsets to be based on actual emissions for the two year period immediately preceding the new emissions unless it can be shown that a different

two year period is more representative of normal operation. This is summarized in the following excerpt from EPA's 1991 workshop document on creditable emission changes:

> "In certain limited situations where the applicant adequately demonstrates that the prior two years is not representative of normal source operation, a different two year time period may be used upon a determination by the reviewing agency that it is more representative of normal source operation." (emphasis added)

Therefore, since EPA requires that any alternate representative period be no more than two years, 1989 and 1991 would be the proper two years on which to base actual emissions for this project. As it turns out, the applicant's proposed offsets based on 1988 through 1990 are within 1% of the 1989/1991 average, therefore the Department can use the applicant's offset estimates. The increased emissions from this project are:

Allowable Emissions (TPY)

	Gas Turbine		Duct Burner	Total	Offsets	Net Increase
	NG	Oil	NG			
NO_x	142.7	7.3	24.6	174.6	134.9	39.7
SO_2	4.3	21.6*	0.7	26.6*	36.1	- 9.5*
PM/PM_{10}	10.2	1.1	2.5	13.8	3.4	10.4
CO	158.0	7.7	36.9	202.6	20.4	182.2
VOC	6.5	0.4	10.6	17.5	1.1	16.4
H_2SO_4	0.3	2.0	0.1	2.4	0.8	1.6

* Estimate based on 0.5% fuel sulfur content

III. Rule Applicability

The construction permit application is subject to review under Chapter 403, Florida Statutes, and Florida Administrative Code (F.A.C.) Chapters 17-2 and 17-4. The proposed facility is subject to the provisions of F.A.C. Rule 17-2.500, Prevention of Significant Deterioration (PSD). The facility is located in an area classified as attainment for all regulated air pollutants. The proposed increase in carbon monoxide (CO) emissions exceeds the significant level set forth in Table 500-2 of F.A.C. Rule 17-2.500. Preconstruction review must include a determination of Best Available Control Technology (BACT), good-engineering practice stack height, ambient impact analysis, impact on soils, vegetation and visibility. Applicable emission limit rules are F.A.C. Rules 17-2.660, Table 660-1, Section 60.330, New Source Performance Standards for Stationary Gas Turbines, Subpart GG, and Section 60.40b, Subpart Db, Industrial/Commercial/Institutional Steam Generating Units. Limits for nitrogen oxides (NOx) and particulate matter (PM) emissions will be based on the turbine manufacturer's performance guarantees since they are more stringent than the NSPS

limits. Existing Boilers 4 and 5 will be subject to F.A.C. Rule 17-2.600(6).

IV. **Air Quality Analysis**

a. Introduction

The operation of the proposed cogeneration facility will result in emissions increases which are projected to be greater than the PSD significant emission rates for the following pollutant: CO. Therefore, the project is subject to the PSD NSR requirements contained in F.A.C. Rule 17-2.500(5) for these pollutants. Part of these requirements is an air quality impact analysis for these pollutants, which includes:

- An analysis of existing air quality;
- An ambient Air Quality Standards analysis (AAQS);
- An analysis of impacts on soils, vegetation, visibility and growth-related air quality impacts; and,
- A Good Engineering Practice (GEP) stack height determinatio

The analysis of existing air quality generally relies on preconstruction monitoring data collected in accordance with EPA-approved methods. The AAQS analyses are based on air quality dispersion modeling completed in accordance with EPA guidelines.

Based on these 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 PSD increment or ambient air quality standard. A brief description of the modeling methods used and results of the required analyses follow. A more complete description is contained in the permit application on file.

b. Analysis of the Existing Air Quality

Preconstruction ambient air quality monitoring may be required for 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 through air quality modeling, is less than a pollutant-specific de minimus concentration. The predicted maximum concentration increase for each pollutant subject to PSD (NSR) is given below:

	CO
PSD de minimus Concentra. (ug/m^3)	575
Averaging Time	8-hr
Maximum Predicted Impact (ug/m^3)	59

c. Modeling Method

The EPA-approved Industrial Source Complex Short-Term (ISCST) dispersion model was used by the applicant to predict the impact of the proposed project on the surrounding ambient air. All recommended EPA default options were used. Downwash parameters were used because the stacks were less than the good engineering practice (GEP) stack height. Five years of sequential hourly surface and mixing depth data from the Jacksonville, Florida/Waycross, GA National Weather Service (NWS) stations collected during 1983 through 1987 were used in the model. Since five years of data were used, the highest-second-high (HSH) short-term predicted concentrations are 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.

d. Modeling Results

The applicant first evaluated the potential increase in ambient ground-level concentrations associated with the project to determine if these predicted ambient concentration increases would be greater than specified PSD significant impact levels for CO. This evaluation was based on the proposed CT units operating at load conditions of 100, 75, 50 and 25 percent. The modeling was performed using the highest emissions at 20°F design condition coupled with the lowest exit gas flow rates at 95°F design condition to maximize predicted impacts. The maximum predicted concentrations generally occur for the maximum capacity at 100% operating load. Dispersion modeling was performed with receptors placed along the 36 standard radial directions (10 degrees apart) surrounding the proposed units at the following downwind distances: 53, 70, 100, 400, 700, 1000, 1300, 1600, 2000, and 2500 km. The results of this modeling presented below show that the increases in ambient ground-level concentrations for all averaging times are less than the PSD significant impact levels for CO.

	CO	
Avg. Time	1-hr	8-hr
PSD Signifi. Level (ug/m^3)	2000	800
Ambient Concen. Increase (ug/m^3)	250	59

e. Additional Impacts Analysis

The proposed modification will not significantly change employment, population, housing or commercial/industrial development in the area to the extent that a significant air quality impact will result.

V. Air Toxics Evaluation

Only negligible quantities of toxic pollutants will be emitted from the limited firing of distillate fuel oil. The quantities are very small and are of no environmental concern.

VI. Conclusion

Based on the information provided by Florida Power Corporation, the Department has reasonable assurance that the proposed installation, 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 Chapter 17-2 of the Florida Administrative Code.

PE # 41755

Florida Department of Environmental Regulation
Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400
Lawton Chiles, Governor
Carol M. Browner, Secretary

PERMITTEE:
Florida Power Corporation
3201 - 34th Street South
St. Petersburg, FL 33733

Permit Number: AC 01-204652
PSD-FL-181
Expiration Date: December 31, 1994
County: Alachua
Latitude/Longitude: 29°38'23"N
82°20'55"W
Project: UF Cogeneration Facility

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-2 and 17-4. 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 and made a part hereof and specifically described as follows:

For the construction of a 43 Megawatt cogeneration facility consisting of replacement of existing boiler Nos. 1, 2, and 3 with a GE LM-6000 combustion turbine in series with a duct burner at a designed flow of 325,200 ACFM, and operating existing boiler Nos. 4 and 5 as auxiliary units.

Particulate emissions shall be controlled by using clean fuels and good combustion practices. CO emissions shall be initially controlled by proper combustion techniques. NO_X emissions shall be initially controlled by steam injection. Future control requirements for CO and NOx will be established by a revised BACT determination if deemed necessary by the Department.

The facility is located at the existing Central Heat Plant on the campus of the University of Florida in Gainseville, Alachua County, Florida. The UTM coordinates are 369.4 km East and 3,279.3 km North.

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

<u>Attachments are listed below</u>:
1. FPC letter dated 11-13-91.
2. FPC letter dated 11-25-91.
3. KBN letter dated 12-2-91.
4. DER incompleteness letter dated 12-31-91.
5. FPC letter dated 1-2-92.
6. EPA letter dated 1-8-92.
7. DER letter to EPA dated 1-16-92.

Attachments Cont'd

8. KBN letter dated 1-30-92.
9. FPC letter to EPA dated 2-6-92.
10. DER letter to EPA dated 2-12-92.
11. DER letter to EPA dated 2-14-92.
12. FPC response to incompleteness dated 3-5-92.
13. FWS letter to DER dated 4-2-92.
14. EPA letter to DER dated 4-8-92.
15. KBN letter to DER dated 4-8-92.

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, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

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), Florida Statutes, 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.

GENERAL CONDITIONS:

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

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 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

GENERAL CONDITIONS:

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 Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. 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 Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-30.300, F.A.C., as applicable. 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)

GENERAL CONDITIONS:

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 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:

1. Unless otherwise indicated, the construction and operation of the subject cogeneration facility shall be in accordance with the capacities and specifications stated in the application.

PERMITTEE:
Florida Power Corporation

Permit Number: AC 01-204652
PSD-FL-181
Expiration Date: December 31, 1994

SPECIFIC CONDITIONS:

2. Emissions from this facility shall not exceed the limits listed below:

Pollutant	Source	Fuel	Basis of Limit	lbs/hr	tons/yr
NOx	Turbine	Gas	EBM*:25 ppmvd @ 15% O2	35.0	142.7
	Turbine	Oil	EBM*:42 ppmvd @ 15% O2	66.3	7.3
	D.Burner	Gas	EBM*:0.1 lb/MMBTU	18.7	24.6
SO2	Turbine	Oil	BACT:0.5% Sulfur Max.	-	-
	Boiler 4	Oil	BACT:0.5% Sulfur Max.	-	-
	Boiler 5	Oil	BACT:0.5% Sulfur Max.	-	-
VE	Turbine	Gas/Oil	Equivalent of mass EBM*	10%/20% opacity**	
	D.Burner	Gas	" " "	10% opacity	
	Boiler 4	Gas/Oil	" " "	10%/20% opacity**	
	Boiler 5	Gas/Oil	" " "	10%/20% opacity**	
CO	Turbine	Gas	BACT:42 ppmvd	38.8	158.0
	Turbine	Oil	EBA***:75 ppmvd	70.5	7.7
	D.Burner	Gas	BACT:0.15 lb/MMBTU****	28.1	36.9

*EBM: Established by manufacturer
**Except for one 6-minute period per hour of not more than 27% opacity
***EBA: Established by applicant
****BACT limit proposed by applicant in Table A-2 of application

3. Fuel consumption rates and hours of operation shall not exceed those listed below:

	Natural Gas			No. 2 Fuel Oil		
	M ft3/hr*	MM ft3/yr	hrs/yr*	M gal/hr*	M gal/yr	hrs/yr*
Turbine	367.9	2997.2**	8146.8**	2.9	635.1	219.0**
Duct Burner	197.7	519.5	2628.0	0	0	0
Boiler No. 4	67.0	10.1	150.0	0.5	7.6	15.2
Boiler No. 5	160.0	63.4	396.0	1.1	25.3	23.0

*Based on maximum firing rates. Units may run at lower rates for more hours within annual fuel limits.

**An additional 1.9 hours/yr operation on natural gas will be allowed for each 1.0 hour/yr that fuel oil is not burned (up to 219 x 1.9 hours/yr), in which case, the emission limits in Specific Condition No. 2 shall be adjusted accordingly.

SPECIFIC CONDITIONS:

4. Before this construction permit expires, the cogeneration facility and Central Heat Plant (Boilers 4 and 5) stacks shall be sampled as applicable according to the emission limits in Specific Condition No. 2. Annual compliance tests shall be conducted each year thereafter. Compliance tests shall be run at 96% to 100% of permitted capacity. Tests shall be conducted using the following reference methods:

NO_x: EPA Method 20
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9
CO: EPA Method 10

5. The DER Northeast District office shall be notified at least 30 days prior to the compliance tests. Compliance test results shall be submitted to the DER Northeast District office and the Bureau of Air Regulation office within 45 days after completion of the tests. Sampling facilities, methods, and reporting shall be in accordance with F.A.C. Rule 17-2.700 and 40 CFR 60, Appendix A.

6. A continuous operations monitoring system shall be installed, operated, and maintained in accordance with 40 CFR 60.334. The natural gas, fuel oil and steam injection flows to the cogeneration turbine along with the power output of the generator shall be metered and continuously recorded. The data shall be logged daily and maintained so that it can be provided to DER upon request.

7. The permittee shall have the option of including, in the initial construction, adequate modules and other provisions necessary for future installation of state-of-the-art catalytic abatement or equivalent CO and NOx control systems. Within 90 days of receipt of the initial compliance test results, the Department shall review the need for making a revised determination of Best Available Control Technology. The Department may revise the BACT determination to require installation of such technology if so indicated by the revised BACT cost/benefit analysis. If the permittee has elected not to provide for future addition of such technology in the initial construction and later applies for a permit modification to increase capacity, the retrofit costs associated with not making provisions for such technology (initially) shall not be considered by the Department in the retrofit cost analysis required for the future expansion.

8. Boilers Nos. 1, 2 and 3 shall permanently cease operation upon receipt of the operation permit for the cogeneration facility.

SPECIFIC CONDITIONS:

9. 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).

10. 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).

Issued this ______ day
of _______________, 1992

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

____
Carol M. Browner, Secretary

Revised
Best Available Control Technology (BACT) Determination
University of Florida Cogeneration Project
Alachua County

The applicant proposes to install a 43 MW cogeneration facility to replace existing boiler capacity at the University of Florida - Gainesville campus in Alachua County. The facility will consist of a General Electric LM-6000 Gas Turbine Generator exhausting through a duct-fired heat recovery steam generator which will produce steam for the University campus. The turbine and duct burner will be fired by natural gas with No. 2 fuel oil being used only as a backup fuel for the turbine.

A BACT determination is required for all regulated air pollutants emitted in amounts equal to or greater than the significant emission rates listed in Table 500-2 of Florida Administrative Code (F.A.C.) Rule 17-2.500.

The following table presents the estimated actual emissions in tons per year proposed by the applicant for NO_x, SO_2, PM/PM_{10}, VOC, and H_2SO_4. The Department accepts the applicant's proposed emissions for those pollutants, but will require a more stringent CO limit for the turbine during natural gas firing than proposed by the applicant (42 ppmvd vs. 75 ppmvd).

	Gas Turbine		Duct Burner	Total	Offsets	Increase	PSD
	NG	Oil	NG				
NO_x	142.7	7.3	24.6	174.6	134.9	39.7	40.0
SO_2	4.3	21.6	0.7	26.6	36.1	-9.5	40.0
PM/PM_{10}	10.2	1.1	2.5	13.8	3.4	10.4	25/15
CO	158.0	7.7	36.9	202.6	20.4	182.2	100.0
VOC	6.5	0.4	10.6	17.5	1.1	16.4	40.0
H_2SO_4	0.3	2.0	0.1	2.4	0.8	1.6	7.0

Emissions are based on firing natural gas in the turbine for 8,147 hours/yr at 348 MMBTU/hr and natural gas in the duct burner for 2,628 hours/yr at 187 MMBTU/hr. Oil firing in the turbine is based on 219 hours/yr at 382.6 MMBTU/hr.

Turbine performance under natural gas firing is based on NO_x emissions of 25 ppmvd (corrected to 15 percent O2). Performance on oil firing is based on NO_x emissions of 42 ppmvd (corrected to 15 percent O2). SO_2 emissions are based on 0.5 percent sulfur.

Date of Receipt of a Complete Application

March 6, 1992

BACT Determination Requested by Applicant

Control Technology: Combustion efficiency for cogeneration CO control.

Emission Limits: 75 ppmvd CO (natural gas or No. 2 oil - 0.5% Sulfur max.)
(No request made for Boilers 4 and 5)

BACT Determined by the Department

Control Technology: Combustion efficiency for cogeneration CO control.

Emission Limits:

Turbine - Natural gas firing:	42 ppmvd CO
Turbine - No. 2 oil firing:	75 ppmvd CO
Maximum % Sulfur - No. 2 oil:	0.5 % S
Duct Burner - Natural gas:	0.15 lb CO/MMBTU
Boilers 4 & 5: (Gas/Oil)	10%/20% Opacity

BACT Determination Procedure

In accordance with F.A.C. Chapter 17-2, 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 control methods, systems and techniques. In addition, the regulations require 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 determinations 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.

A review of EPA's BACT/LAER Clearinghouse indicates that catalytic oxidation is the most stringent control technique. An oxidation catalyst control system allows unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F and reaches near completion (above 90%) at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than for thermal oxidation thus reducing the thermal energy required. The oxidation catalyst is typically located directly after the turbine or as an integral part of the steam generator. Catalyst size depends on the exhaust flow, temperature, and desired efficiency.

Catalytic oxidation for CO control has been employed in nonattainment areas and is considered to be LAER technology capable of reducing CO emissions to the 10 ppm range. Due to economics, applications of catalytic oxidation technology have thus far been limited to small cogeneration facilities burning natural gas. Oxidation catalysts have not been used on base-loaded fuel oil-fired turbines in simple cycle or combined cycle facilities since extended use of sulfur-containing fuel would result in increased corrosion. Also, trace metals in the fuel could poison catalysts during prolonged fuel oil firing.

Using the applicant's proposed CO emission level of 75 ppmvd, the total annualized cost of CO catalytic oxidation for this project is $508,156 with a cost effectiveness of about $1,970/ton of CO removed. The cost effectiveness is based on 87% efficiency (75 ppmvd to 10 ppmvd) and includes a heat rate penalty of 0.2% based on an energy loss of $50/MW associated with pressure drop across the catalyst. A review of previous BACT determinations indicates that $1,970/ton would not be prohibitive. However, the decision to require catalytic oxidation should be based on a cost/benefit analysis once compliance testing has been done. Therefore, the Department will propose initial BACT emission limits for CO consistent with recent BACT determinations for similar sources. These limits are to be revised, if necessary, upon evaluation of the compliance test data. The turbine limit proposed by the applicant for fuel oil operation (75 ppmvd) is more stringent than a recent BACT determination for similar sources (78 ppmvd).

Other Air Pollutants Not Subject to BACT Determination

The application indicates that emissions of other pollutants will not be subject to a BACT determination. The applicant narrowly escaped PSD review for NO_x by lowering firing rates, and since increased firing rates may be requested at some future date, the Department will require that retrofit costs associated with the applicant's decision not to make initial provisions for future installation of advanced catalytic control shall not be considered in any cost analysis required for any future requested increase in capacity.

Details of the Analysis May be Obtained by Contacting:

Preston Lewis, P.E., BACT Coordinator
Department of Environmental Regulation
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	Carol M. Browner, Secretary Dept. of Environmental Regulation
________________________1992 Date	________________________1992 Date

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

FLORIDA POWER CORPORATION

Petitioner,

vs. OGC CASE NO. 92-1113

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION,

Respondent.
_______________________________/

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

This cause has come before me upon receipt of a request made by Petitioner, Florida Power Corporation, pursuant to Florida Administrative Code Rule 17-103.070, to grant an extension of time to file a petition for administrative hearing concerning the Department's Application No. AC01-204652. See Exhibit A attached.

Counsel for Petitioner has discussed this request with counsel for Respondent, State of Florida Department of Environmental Regulation (DER), and the DER 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 and including July 24, 1992, to file a petition

Department of Environmental Regulation

Routing and Transmittal Slip

To: (Name, Office, Location)

1. Patty adams (B/c 0)
2. ~~John~~
3. Patty (file)
4.

Remarks:

RECEIVED

JUN 24 1992

Division of Air
Resources Management

From: Bill Congdon

Date 6-23

Phone

in this matter. Filing shall be complete upon receipt by the Department's Office of General Counsel, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400.

DONE and ORDERED this 23rd day of June, 1992, in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

DANIEL H. THOMPSON
General Counsel
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: 904/488-9730

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished to W. Jeffrey Pardue, Manager, Florida Power Corporation, Post Office Box 14042, Saint Petersburg, Florida 33733, by U.S. Mail on this 24th day of June, 1992.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

WILLIAM CONGDON
Assistant General Counsel
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: (904) 488-9730

Florida
Power
CORPORATION

June 15, 1992

Mr. Richard Donelan, Esq.
Office of General Counsel
Florida Department of Environmental Regulation
2600 Blairstone Rd.
Tallahassee, Florida 32399-2400

Dear Mr. Donelan:

Re: Florida Power Corporation/University of Florida Cogeneration Project
Permit No. AC 01-204652, PSD-FL-181

On June 8, 1992, Florida Power Corporation (FPC) received the Technical Evaluation and Preliminary Determination and proposed air construction permit for the above referenced facility. A review of the permit conditions has revealed that several issues remain to be resolved. I have had conversations with Mr. Clair Fancy of FDER and he has agreed that an extention of time to discuss these issues is appropriate. Therefore, based upon Mr. Fancy's recommendation and pursuant to Section 17-120.070, FAC, FPC respectfully requests an extension of time in which to file a petition for an administrative hearing under Section 120.57 FS, up to and including June 24, 1992.

If you should have any questions, please contact Mr. Scott Osbourn at (813) 866-5158.

Sincerely,

W. Jeffrey Pardue, Manager
Environmental Programs

cc: C. Fancy, FDER-Tallahassee

Airborne Express
Airbill #
004055929 846

RECEIVED
JUN 23 1992
Bureau of
Air Regulation

Florida
Power
CORPORATION

June 19, 1992

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

Re: University of Florida Cogeneration Project
Permit No. AC 01-204652, PSD-FL-181

Dear Mr. Fancy:

On June 8, 1992, Florida Power Corporation (FPC) received the draft air permit for the above referenced facility. Based upon discussions between the Florida Department of Environmental Regulation (FDER) and FPC, it was agreed that a meeting would be held in Tallahassee to discuss several of the draft permit conditions. At your direction, this letter serves to transmit FPC's understanding of the conclusions and agreements reached at our subsequent June 17, 1992 meeting. In addition, please find attached a revision of the draft permit which incorporates FPC's understanding, as discussed in the following paragraphs.

Specific Condition 2. This conditon lists all emission limits, by pollutant and source type, not to be exceeded. Based upon discussions at the June 17, 1992 meeting, the draft permit combustion turbine (CT) SO_2 limits were determined to be inappropriate. Previously, the limit for the turbine was suggested as BACT; however, at the requested emission limit of 0.5 percent sulfur, there will be a net reduction of SO_2 emissions. FDER had accepted the net reduction of SO_2 emissions using 0.5 percent sulfur in their BACT analysis and project description and correctly concluded that PSD review was not applicable.

Second, regarding Boilers 4 and 5, the small fossil fuel steam generator emission limit (FDER Rule 17-2.600(6)F.A.C.) is applicable to new and existing sources with a heat input of less than 250 million BTU/hr unless otherwise specified by rule or by order or permit issued by FDER prior to July 15, 1989. The latter indicates that the rule does not apply if limits are established by permit prior to July 15, 1989. As indicated in conditions of the current air permits for Boilers 4 and 5, a BACT determination was made September 24, 1987 and indicated a 1.5 percent sulfur limit. The requested permit does not indicate any modification of the boilers, except lowering the fuel usage and sulfur content (to 0.5 percent). FPC agrees to accept a limit on Boilers 4 and 5 of 0.5 percent fuel oil sulfur.

The same comments apply for FDER's suggested visible emissions (VE) limit. The turbine VE limit is the same as the recent FDER BACT determinations for the Lake and Pasco Cogen permits. However, while those projects were subject to a BACT determination for particulates and opacity, this project is not. Similarly, as stated above, FPC believes that a BACT determination on opacity for the existing boilers is inappropriate. During our meeting, an agreement was reached allowing 10 percent opacity for the combustion turbine (CT) and boilers while firing natural gas, 20 percent opacity for the CT and boilers while firing fuel oil, and an allowance to 27 percent opacity for the CT and boilers during startups, shutdowns and load swings.

Specific Condition 3. This condition seems inconsistent given the use of heat input (i.e., million BTU) in previous permits. Maximum annual heat inputs for the CT, duct burner, and boilers were provided by FPC to FDER in a revised application submittal dated March 5, 1992. Regarding the footnotes to S.C. 3, FPC had requested the allowance for trading oil operation for natural gas; however, Specific Condition 2 does not provide this allowance. This can be accomplished through limiting the annual emissions in S.C. 2 to the total emissions of the turbine firing natural gas and oil, and the duct burner firing natural gas. In addition, footnotes 3 and 4 have been added to the table in S.C. 3 allowing operating flexibility.

Specific Condition 4. There are no emission limits for Boilers 4 and 5 for either NO_x or CO. Therefore, this reference was removed. Concerning the combustion turbine, FDER practice has allowed testing of 90 percent or greater of permitted capacity in current permits. In order to allow the necessary flexibility for real-world operation and testing conditions, the condition was revised to read:"...between 90 and 100 percent of permitted capacity during compliance testing, as adjusted for ambient temperature."

Specific Condition 6. This condition should be eliminated; such a condition is vague and, to the best of our knowledge, has never been in any previous permits issued by FDER.

Specific Condition 7. There is no requirement in the NSPS to monitor power output. Therefore, this reference was removed.

Specific Condition 8. The reference to NO_x was modified as BACT review for NO_x was not performed. The references for reviewing BACT for CO were modified consistent with that contained in the Lake and Pasco Cogen permits. Further, the CO duct burner limit was revised to be consistent with that proposed in other recent permits for identical machines (0.2 lb/million BTU).

Specific Condition 9. The language in this condition was changed to read: "...cease operation upon receipt of the operating permit for the cogeneration facility."

Regarding the appropriateness of FDER requiring a duct module for NO_x, FDER's authority for establishing specific permit conditions is contained in Rule 17-4.070. In establishing any specific condition, such condition must be "necessary to provide reasonable assurance that department rules can be met" (Rule 17-4.070(3)F.A.C.). The requirement for a duct module must meet this test. FPC believes that reasonable assurance was provided that the proposed limit would be met through manufacturer guarantees. No other permit that is not undergoing BACT has had such a limit. The requirement for a duct module is clearly unreasonable and does not meet the necessary test of the FDER rules.

FPC appreciates the opportunity to present our concerns for discussion and we look forward to issuance of a revised draft permit. As we discussed, FPC would like to submit the revised draft for publication by the end of this month.

Sincerely,

Scott Osborne for

W. Jeffrey Pardue, Manager
Environmental Programs

cc: Preston Lewis, FDER-Tallahassee
J. Reynolds
C. Holladay
A. Kutyna, NE Dist.
J. Harper, EPA
C. Shaver, NPS

SPECIFIC CONDITIONS:

1. Unless otherwise indicated, the construction and operation of the subject cogeneration facility shall be in accordance with the capacities and specifications stated in the application.

2. Emissions from this facility shall not exceed the limits listed below:

Pollu-tant	Source	Fuel	Basis of Limit	lbs./hr	tons/yr.[2]
NOx	Turbine	Gas	EBM[1]:25 ppmvd @ 15% 02	35.0	142.7
	Turbine	Oil	EBM[1]:42 ppmvd @ 15% 02	66.3	7.3
	D.Burner	Gas	EBM[1]:0.1 lb/MMBTU	18.7	24.6
SO2	Turbine	Oil	~~BACT:0.1%~~ Sulfur Max. EBA[1]0.5%	-	-
	Boiler 4	Oil	~~BACT:0.1%~~ Sulfur Max. EBA[1]0.5%	-	-
	Boiler 5	Oil	~~BACT 0.1%~~ Sulfur Max. EBA[1]0.5%	-	-
VE[3]	Turbine	Gas/Oil	Equivalent of mass EBM[1]		~~10% opacity~~ 10%/20% opacity
	D.Burner	Gas	" " "		10% opacity
	Boiler 4	Gas/Oil	" " "		~~10% opacity~~ 10%/20% opacity
	Boiler 5	Gas/Oil	" " "		~~10% opacity~~ 10%/20% opacity
CO	Turbine	Gas	BACT:42 ppmvd	~~38.8~~ 69.5	~~158.0~~ 282.1
	Turbine	Oil	~~EBA[1]~~BACT :75 ppmvd	70.5	7.7
	D.Burner	Gas	BACT:0.2 lb/MMBTU	28.1	36.9

(1) EBM: Established by manufacturer
EBA: Established by applicant

(2) An additional 1.9 hours/yr operation on natural gas will be allowed for each 1.0 hour/yr that fuel oil is not burned (up to 219 x 1.9 hours/yr).

(3) Allowable VE's during startup, shutdown, and load swings is 27%

3. Fuel consumption rates and hours of operation shall not exceed those listed below:

	NATURAL GAS			NO. 2 FUEL OIL		
	Mft.^{3}/hr[1]	MM ft.^{3}/yr	hrs./yr[1]	M gal./hr[1]	M gal./yr	hrs./yr[2]
Turbine	367.9	2997.2[2]	8146.8[2]	2.9	635.1[2]	219.0[2]
Duct Burner	197.7	519.5	2628.00	0	0	
~~Boiler No. 4~~	~~67.0~~	~~10.1~~	~~150.0~~	~~0.5~~	~~7.6~~	~~15.2~~
Boiler No. 4	67.0	20.0[4]	150.0	0.5	15.0[3]	15.2
~~Boiler No. 5~~	~~160.0~~	~~63.4~~	~~396.0~~	~~1.1~~	~~25.3~~	~~23.0~~
Boiler No. 5	160.0	125.0[4]	396.0	1.1	50.0[3]	23.0

(1) Based on maximum firing rates. Units may run at lower rates for more hours within annual fuel limits.

(2) An additional 1.9 hours/yr operation on natural gas will be allowed for each 1.0 hour/yr that fuel oil is not burned (up to 219 x 1.9 hours/yr).

(3) The usage of oil for boilers 4 and 5 may be increased by 0.96 gallons of oil for every gallon not burned in the turbine. The total amount of oil used in the turbine will be reduced by this amount.

(4) The usage of natural gas for boilers 4 and 5 may be increased by 0.34 cubic feet for every cubic foot not burned in the burbine. The total amount of natural gas used in the turbine will be reduced by this amount.

4. Before this construction permit expires, the cogeneration facility ~~and Central Heat Plant (Boilers 4 and 5)~~ stack shall be sampled according to the emission limits in Specific Condition No. 2. Annual compliance tests shall be conducted each year thereafter. ~~Compliance tests shall be run at 100% of permitted capacity.~~ The source shall operate between 90 and 100 percent of permitted capacity during compliance testing as adjusted for ambient temperature. Tests shall be conducted using the following reference methods:

NO_X: EPA Method 20
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9
CO: EPA Method 10

5. The DER Northeast District office shall be notified at least 30 days prior to the compliance tests. Compliance test results shall be submitted to the DER Northeast District office and the Bureau of Air Regulation office within 45 days after completion of the tests. Sampling facilities, methods, and reporting shall be in accordance with F.A.C. Rule 17-2.700 and 40 CFR 60, Appendix A.

~~6. Within 60 days of receipt of the compliance test results, the DER Bureau of Air Regulation in Tallahassee will re-evaluate the BACT determination.~~

~~7.~~6. ~~A continuous operations monitoring system shall be installed, operated, and maintained in accordance with 40 CFR 60.334. The natural gas, fuel oil and steam injection flows to the cogeneration turbine along with the power output of the generator shall be metered and continuously recorded.~~ The water/steam to fuel ratio at which compliance is achieved shall be incorporated into the operation permit and shall be continuously monitored. The data shall be logged daily and maintained so that it can be provided to DER upon request.

~~8.~~7. ~~The permittee shall include in the initial construction adequate modules and other provisions necessary for future installation of state-of-the-art catalytic abatement or equivalent CO and NO_x control systems. Following receipt of the initial compliance test results, the Department may make a revised determination of Best Available Control Technology and may require installation of such technology~~. Combustion control shall be utilized for CO control. Due to the lack of operational experience with the LM6000 and the uncertainty of actual CO emissions, the permittee shall leave a space suitable for future installation of an oxidation catalyst. If compliance testing indicates that the applicant is unable to meet the CO limits established in Table 2, the decision to require an oxidation catalyst will be based on a cost/benefit analysis of using such control.

8. The Department will not require the applicant to provide modular space for a NO_x post-combustion abatement system, nor provide for the system itself. However, if the permittee is subject to future new source review requirements, the additional retrofit costs associated with not providing space during the initial project construction cannot be factored into the NO_x control cost-effectiveness analysis.

9. Boilers Nos. 1, 2 and 3 shall permanently cease operation ~~prior to the startup of~~ upon receipt of the operating permit for the cogeneration facility.

10. 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 17-3.090).

11. 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).

Best Available Control Technology (BACT) Determination
University of Florida Cogeneration Project
Alachua County

The applicant proposes to install a 43 MW cogeneration facility to replace existing boiler capacity at the University of Florida - Gainesville campus in Alachua County. The facility will consist of a General Electric LM-6000 Gas Turbine Generator exhausting through a duct-fired heat recovery steam generator which will produce steam for the University campus. The turbine and duct burner will be fired by natural gas with No. 2 fuel oil being used only as a backup fuel for the turbine.

A BACT determination is required for all regulated air pollutants emitted in amounts equal to or greater than the significant emission rates listed in Table 500-2 of Florida Administrative Code (F.A.C.) Rule 17-2.500.

Maximum annual emissions from the proposed project are listed below in tons per year:

	Gas Turbine NG	Gas Turbine Oil	Duct Burner NG	Total	Offsets	Increase	PSD
NO_X	142.7	7.3	24.6	174.6	134.9	39.7	40.0
SO_2	4.3	21.6	0.7	26.6	36.1	-9.5	40.0
PM/PM_{10}	10.2	1.1	2.5	13.8	3.4	10.4	25/15
CO	158.0	7.7	24.6	190.3	20.4	169.9	100.0
VOC	6.5	0.4	10.6	17.5	1.1	16.4	40.0
H_2SO_4	0.3	2.0	0.1	2.4	0.8	1.6	7.0

Emissions are based on firing natural gas in the turbine for 8,147 hours/yr at 348 MMBTU/hr and natural gas in the duct burner for 2,628 hours/yr at 187 MMBTU/hr. Oil firing in the turbine is based on 219 hours/yr at 382.6 MMBTU/hr. Regarding the turbine operation, an additional 1.9 hours/yr operation on natural gas will be allowed for each 1.0 hour/yr that fuel oil is not burned (up to 219 x 1.9 hours/yr).

The usage of oil for boilers 4 and 5 may be increased by 0.96 gallons of oil for every gallon not burned in the turbine. The total amount of oil used in the turbine will be reduced by this amount. The usage of natural gas for boilers 4 and 5 may be increased by 0.34 cubic feet for every cubic foot not burned in the turbine. The total amount of natural gas used in the turbine will be reduced by this amount.

Calculation for Boiler 4 and 5 Oil Tradeoff:

- NO_X Emissions from turbine on oil:

  66.3 lb/hour $\div$ 382.6×10^6 BTU/hr = 0.1733 lb/10^6 BTU

- NO_X Emissions from Boilers 4 and 5:

  24 lb NO_X /10^3 gal. x gal./7.2 lb x lb/18,400 BTU =
  0.1812 lb NO_X/10^6BTU

(Highest emissions from Boiler 5 were used)

- Oil Tradeoff Ratio = 0.1733 lb/10^6 BTU ÷ 0.1812lb/10^6 BTU = 0.96

Notes:
1) Turbine and boilers will use same fuel. Therefore, BTU equivalents and gallons will be the same.
2) Emissions of other pollutants such as SO_2 will virtually be the same from turbine and boiler.

Calculation of Boiler 4 and 5 Natural Gas Tradeoff:

- NO_x Emissions from turbine on natural gas:

35.0 lb/hr ÷ 348 x 10^6 BTU/hr = 0.1006 lb/10^6 BTU

- No_x Emissions from Boilers 4 and 5 on natural gas:

281.2 lb NO_x/MMscf x MMscf/946 x 10^6 BTU = 0.2973 lb/10^6 BTU

(Highest emissions from Boiler 5 were used)

- Natural Gas Trade-Off Ratio = 0.1006 lb/10^6 BTU ÷ 0.2973 lb/10^6 BTU = 0.34

Notes:
1) Turbine and boilers will use the same fuel, therefore, BTU equivalents and cubic feet will be the same.
2) Emissions of other pollutants such as SO_2 will virtually be the same from the turbine and the boilers.

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

March 6, 1992

<u>BACT Determination Requested by Applicant</u>

Control Technology: Combustion efficiency for cogeneration CO control.

Emission Limits: 75 ppmvd CO (natural gas or No. 2 oil - 0.5% sulfur max.)
(No request made for Boilers 4 and 5)

<u>BACT Determined by the Department</u>

Control Technology: Combustion efficiency for cogeneration CO control with provision for future installation of an oxidation catalyst system. Once performance testing has been completed and the applicant has failed to meet the CO limits established in Table 2, the decision to require an oxidation catalyst will be based on a cost/benefit analysis of using such control.

Emission Limits:	Turbine - natural gas firing:	42 ppmvd CO
	Turbine - No. 2 oil firing:	75 ppmvd CO
	Boilers 4 & 5 - Max. % S:	~~0.1% S~~ 0.5% S
	Duct Burner - Natural gas:	~~0.1 lb CO/MMBTU~~ 0.2 lb CO/MMBTU
	Boilers 4 & 5 (Gas/Oil):	10%/20% opacity

BACT Determination Procedure

In accordance with F.A.C. Chapter 17-2, 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 control methods, systems and techniques. In addition, the regulations require 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 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 determinations 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.

A review of EPA's BACT/LAER Clearinghouse indicates that catalytic oxidation is the most stringent control technique. An oxidation catalyst control system allows unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F and reaches near completion (above 90%) at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than for thermal oxidation thus reducing the thermal energy required. The oxidation catalyst is typically located directly after the turbine or as an integral part of the steam generator. Catalyst size depends on the exhaust flow, temperature, and desired efficiency.

Catalytic oxidation for CO control has been employed in nonattainment areas and is considered to be LAER technology capable of reducing CO emissions to the 10 ppm range. Due to economics, applications of catalytic oxidation technology have thus far been limited to small cogeneration facilities burning natural gas. Oxidation catalysts have not been used on base-loaded fuel oil-fired turbines in simple cycle or combined cycle facilities since extended use of sulfur-containing fuel would result in increased corrosion. Also, trace metals in the fuel could poison catalysts during prolonged fuel oil firing. ~~For these reasons, if catalytic oxidation is required upon re-evaluation of the BACT, the permit will be amended to allow natural gas firing only.~~

Using the applicant's proposed CO emission level of 75 ppmvd, the total annualized cost of CO catalytic oxidation for this project is $508,156 with a cost effectiveness of about $1,970/ton of CO removed. The cost effectiveness is based on 87% efficiency (75 ppmvd to 10 ppmvd) and includes a heat rate penalty of 0.2% based on an energy loss of $50/MW associated with pressure drop across the catalyst. A review of previous BACT determinations indicates that $1,970/ton would not be prohibitive. However, since the applicant is required to provide space for an oxidation catalyst retrofit the decision to require catalytic oxidation should be based on a cost/benefit analysis once compliance testing has been ~~done~~completed and if the applicant is unable to meet the CO emission limits established in Table 2. ~~with the provision for future installation being made a condition of the original construction permit~~. Therefore, the Department will propose initial BACT emission limits for CO consistent with recent BACT determinations for similar sources. These limits are to be revised, ~~if necessary, upon evaluation of the compliance test data~~ if installation of an oxidation catalyst is warranted. The turbine limit proposed by the applicant for fuel oil operation (75 ppmvd) is more stringent than a recent BACT determination for similar sources (78 ppmvd).

Other Air Pollutants Not Subject to BACT Determination

The application indicates that emissions of other pollutants will not be subject to a BACT determination. ~~Since the applicant narrowly escaped PSD review for NO_x by lowering firing rates, and since increased firing rates may be requested at some future date, the Department will require that the applicant make provisions for future installation of state-of-the-art catalytic abatement technology for control of NO_x emissions, such as would presently be required if the source was subject to a NO_x BACT determination.~~

Details of the Analysis May be Obtained by Contacting:

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

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

JUN 16 1992

RECEIVED
JUN 19 1992
Division of Air
Resources Management

4APT-AEB

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

RE: Florida Power Corp. - U of F Project (PSD-FL-181)

Dear Mr. Fancy:

This is to acknowledge receipt of your preliminary determination and draft Prevention of Significant Deterioration (PSD) permit for the above referenced facility by letter dated June 2, 1992. The proposed modification involves the shutdown of three existing boilers and the construction of a combined cycle combustion turbine (GE LM 6000 model). As a result of the shutdowns, the modification will have a significant increase in emissions for CO only.

We have reviewed the package as requested and have no adverse comments. If you have any questions or comments on this project, please contact Mr. Gregg Worley of my staff at (404) 347-5014.

Sincerely yours,

Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides, and Toxics
Management Division

cc: J. Reynolds
C. Holladay
A. Kutyna, NE Dist
C. Shaver NPS
K. Kosky, KBN
CHF/PL

Florida Power CORPORATION

RECEIVED

JUN 18 1992

Division of Air Resources Management

June 15, 1992

Mr. Richard Donelan, Esq.
Office of General Counsel
Florida Department of Environmental Regulation
2600 Blairstone Rd.
Tallahassee, Florida 32399-2400

Dear Mr. Donelan:

Re: Florida Power Corporation/University of Florida Cogeneration Project
Permit No. AC 01-204652, PSD-FL-181

On June 8, 1992, Florida Power Corporation (FPC) received the Technical Evaluation and Preliminary Determination and proposed air construction permit for the above referenced facility. A review of the permit conditions has revealed that several issues remain to be resolved. I have had conversations with Mr. Clair Fancy of FDER and he has agreed that an extention of time to discuss these issues is appropriate. Therefore, based upon Mr. Fancy's recommendation and pursuant to Section 17-120.070, FAC, FPC respectfully requests an extension of time in which to file a petition for an administrative hearing under Section 120.57 FS, up to and including June 24, 1992.

If you should have any questions, please contact Mr. Scott Osbourn at (813) 866-5158.

Sincerely,

W. Jeffrey Pardue, Manager
Environmental Programs

cc: C. Fancy, FDER-Tallahassee

GENERAL OFFICE: 3201 Thirty-fourth Street South • P.O. Box 14042 • St. Petersburg, Florida 33733 • (813) 866-5151
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POST OFFICE BOX 14042, ST. PETERSBURG, FLORIDA 33733

Florida Power
CORPORATION

Mr. C. Fancy
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

951 675(S)

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

June 2, 1992

CERTIFIED MAIL-RETURN RECEIPT REQUESTED

Mr. R. W. Neiser
Senior Vice President-Legal and Gov. Affairs
Florida Power Corporation
3201-34th Street South
St. Petersburg, Florida 33733

Dear Mr. Neiser:

Attached is one copy of the Technical Evaluation and Preliminary Determination and proposed permit for Florida Power Corporation to construct a cogeneration facility at the University of Florida in Gainesville.

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

Sincerely,

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

CHF/JR/plm

Attachments

c: A. Kutyna, NED
J. Harper, EPA
C. Shaver, NPS
K. Kosky, KBN

P 710 058 538

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

Sent to Mr. R. W. Neiser, FPC	
Street & No. 3201-34th St. South	
P.O., State & ZIP Code St. Petersburg, FL 33733	
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Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 6-2-92 Permit: AC 01-204652 PSD-FL-181	

PS Form **3800**, June 1990

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

CERTIFIED MAIL

In the Matter of an
Application for Permit by:

DER File No. AC 01-204652
PSD-FL-181

Florida Power Corporation
3201-34th Street South
St. Petersburg, Florida 33733
_______________________________/

INTENT TO ISSUE

The Department of Environmental Regulation 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, Florida Power Corporation, applied on March 6, 1992, to the Department of Environmental Regulation for a permit to construct a cogeneration facility at the University of Florida in Gainesville, Alachua County, Florida.

The Department has permitting jurisdiction under the provisions of Chapter 403, Florida Statutes and Florida Administrative Code (F.A.C.) Chapters 17-2 and 17-4. 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, Florida Statutes and Rule 17-103.150, 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. Where there is more than one newspaper of general circulation in the county, the newspaper used must be one with significant circulation in the area that may be affected by the permits. If you are uncertain that a newspaper meets these requirements, please contact the Department at the address or telephone number listed on the fourth page. 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, Florida Statutes. The petition must contain the information set forth below and must be filed (received) in the Office of General Counsel of the Department at 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, Florida Statutes.

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 REGULATION

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 6-2-92 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 6-2-92
Date

Copies furnished to:

A. Kutyna, NED
J. Harper, EPA
C. Shaver, NPS
K. Kosky, KBN

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

The Department of Environmental Regulation gives notice of its intent to issue a permit to Florida Power Corporation, 3201 - 34th Street South, St. Petersburg, Florida 33733, to construct a 43 MW cogeneration facility on Mowry Road at the University of Florida campus in Gainesville, Alachua County, Florida. A determination of Best Available Control Technology (BACT) was required. The proposed project is subject to Prevention of Significant Deterioration (PSD) regulations in regard to carbon monoxide emissions and federal new source performance standards for nitrogen oxides. Modeling results show that increases in ground-level concentrations are less than PSD significant impact levels for carbon monoxide. 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. 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, Florida Statutes.

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, F.A.C.

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

Department of Environmental Regulation
Northeast District
7825 Baymeadows Way, Suite B200
Jacksonville, Florida 32256-7577

Any person may send written comments on the proposed action to Mr. Preston Lewis 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. Such requests must be submitted within 30 days of this notice.

Technical Evaluation
and
Preliminary Determination

Florida Power Corporation/University
of Florida Cogeneration Project
Alachua County, Florida

Permit No. AC 01-204652
PSD-FL-181

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

June 2, 1992

I. Application Information

A. Applicant

Florida Power Corporation
3201 - 34th Street South
St. Petersburg, Florida 33733

B. Request

The Department received a complete application on March 6, 1992, for a permit to construct a 43 megawatt (MW) cogeneration facility at the existing University of Florida Central Heat Plant in Gainesville.

C. Classification/Location

The subject facility (SIC Code 8221) is located on Mowry Road at the University of Florida Campus in Gainesville. Latitude and longitude are 29°38'23"N and 82°20'55"W, respectively. The UTM coordinates of the site are: 369.4 km E and 3,279.3 km N.

II. Project Description/Emissions

The applicant proposes to construct a 43 MW cogeneration facility to replace existing Boilers 1, 2, and 3 and part of the current capacity of Boilers 4 and 5. The University's power and steam requirements will be provided by a General Electric LM-6000 gas turbine generator exhausting into a heat recovery steam generator producing 112,500 lbs/hr steam for the UF campus. The cogeneration facility will be located next to the existing Heat Plant No. 2. Primary fuel for the cogeneration facility will be natural gas. Distillate fuel oil will be used for up to 219 hours/yr.

The following discussion concerns how emissions offsets were determined. Since fuel use at the subject facility was abnormally low in 1990, the applicant requested that offsets be based on a three year period (1988-1990). EPA regulations require offsets to be based on actual emissions for the two year period immediately preceding the new emissions unless it can be shown that a different <u>two year</u> period is more representative of normal operation. This is summarized in the following excerpt from EPA's 1991 workshop document on creditable emission changes:

> "In certain limited situations where the applicant adequately demonstrates that the prior two years is not representative of normal source operation, a different <u>two year</u> time period may be used upon a determination by the reviewing agency that it is more representative of normal source operation." (emphasis added)

Therefore, since EPA requires that any alternate representative period be no more than two years, 1989 and 1991 would be the proper two years on which to base actual emissions for this project. As it turns out, the applicant's proposed offsets based on 1988 through 1990 are within 1% of the 1989/1991 average, therefore the Department can use the applicant's offset estimates. The increased emissions from this project are:

Allowable Emissions (TPY)

	Gas Turbine NG	Gas Turbine Oil	Duct Burner NG	Total	Offsets	Net Increase
NO_x	142.7	7.3	24.6	174.6	134.9	39.7
SO_2	4.3	21.6	0.7	26.6	36.1	- 9.5
PM/PM_{10}	10.2	1.1	2.5	13.8	3.4	10.4
CO	158.0	7.7	24.6	190.3	20.4	169.9
VOC	6.5	0.4	10.6	17.5	1.1	16.4
H_2SO_4	0.3	2.0	0.1	2.4	0.8	1.6

III. Rule Applicability

The construction permit application is subject to review under Chapter 403, Florida Statutes, and Florida Administrative Code (F.A.C.) Chapters 17-2 and 17-4. The proposed facility is subject to the provisions of F.A.C. Rule 17-2.500, Prevention of Significant Deterioration (PSD). The facility is located in an area classified as attainment for all regulated air pollutants. The proposed increase in carbon monoxide (CO) emissions exceeds the significant level set forth in Table 500-2 of F.A.C. Rule 17-2.500. Preconstruction review must include a determination of Best Available Control Technology (BACT), good-engineering practice stack height, ambient impact analysis, impact on soils, vegetation and visibility. Applicable emission limit rules are F.A.C. Rules 17-2.660, Table 660-1, Section 60.330, New Source Performance Standards for Stationary Gas Turbines, Subpart GG, and Section 60.40b, Subpart Db, Industrial/Commercial/Institutional Steam Generating Units. Limits for nitrogen oxides (NOx) and particulate matter (PM) emissions will be based on the turbine manufacturer's performance guarantees since they are more stringent than the NSPS limits. Existing Boilers 4 and 5 will be subject to F.A.C. Rule 17-2.600(6).

IV. **Air Quality Analysis**

a. Introduction

The operation of the proposed cogeneration facility will result in emissions increases which are projected to be greater than the PSD significant emission rates for the following pollutant: CO. Therefore, the project is subject to the PSD NSR requirements contained in F.A.C. Rule 17-2.500(5) for these pollutants. Part of these requirements is an air quality impact analysis for these pollutants, which includes:

- An analysis of existing air quality;
- An ambient Air Quality Standards analysis (AAQS);
- An analysis of impacts on soils, vegetation, visibility and growth-related air quality impacts; and,
- A Good Engineering Practice (GEP) stack height determinatio

The analysis of existing air quality generally relies on preconstruction monitoring data collected in accordance with EPA-approved methods. The AAQS analyses are based on air quality dispersion modeling completed in accordance with EPA guidelines.

Based on these 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 PSD increment or ambient air quality standard. A brief description of the modeling methods used and results of the required analyses follow. A more complete description is contained in the permit application on file.

b. Analysis of the Existing Air Quality

Preconstruction ambient air quality monitoring may be required for 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 through air quality modeling, is less than a pollutant-specific de minimus concentration. The predicted maximum concentration increase for each pollutant subject to PSD (NSR) is given below:

	CO
PSD de minimus Concentra. (ug/m^3)	575
Averaging Time	8-hr
Maximum Predicted Impact (ug/m^3)	59

c. Modeling Method

The EPA-approved Industrial Source Complex Short-Term (ISCST) dispersion model was used by the applicant to predict the impact of the proposed project on the surrounding ambient air. All recommended EPA default options were used. Downwash parameters were used because the stacks were less than the good engineering practice (GEP) stack height. Five years of sequential hourly surface and mixing depth data from the Jacksonville, Florida/Waycross, GA National Weather Service (NWS) stations collected during 1983 through 1987 were used in the model. Since five years of data were used, the highest-second-high (HSH) short-term predicted concentrations are 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.

d. Modeling Results

The applicant first evaluated the potential increase in ambient ground-level concentrations associated with the project to determine if these predicted ambient concentration increases would be greater than specified PSD significant impact levels for CO. This evaluation was based on the proposed CT units operating at load conditions of 100, 75, 50 and 25 percent. The modeling was performed using the highest emissions at 20°F design condition coupled with the lowest exit gas flow rates at 95°F design condition to maximize predicted impacts. The maximum predicted concentrations generally occur for the maximum capacity at 100% operating load. Dispersion modeling was performed with receptors placed along the 36 standard radial directions (10 degrees apart) surrounding the proposed units at the following downwind distances: 53, 70, 100, 400, 700, 1000, 1300, 1600, 2000, and 2500 km. The results of this modeling presented below show that the increases in ambient ground-level concentrations for all averaging times are less than the PSD significant impact levels for CO.

	CO	
Avg. Time	1-hr	8-hr
PSD Signifi. Level (ug/m^3)	2000	800
Ambient Concen. Increase (ug/m^3)	250	59

e. Additional Impacts Analysis

The proposed modification will not significantly change employment, population, housing or commercial/industrial development in the area to the extent that a significant air quality impact will result.

V. Air Toxics Evaluation

Only negligible quantities of toxic pollutants will be emitted from the limited firing of distillate fuel oil. The quantities are very small and are of no environmental concern.

VI. Conclusion

Based on the information provided by Florida Power Corporation, the Department has reasonable assurance that the proposed installation, 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 Chapter 17-2 of the Florida Administrative Code.

#41755

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

PERMITTEE:
Florida Power Corporation
3201 - 34th Street South
St. Petersburg, FL 33733

Permit Number: AC 01-204652
PSD-FL-181
Expiration Date: December 31, 1994
County: Alachua
Latitude/Longitude: 29°38'23"N
82°20'55"W
Project: UF Cogeneration Facility

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Chapters 17-2 and 17-4. 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 and made a part hereof and specifically described as follows:

For the construction of a 43 Megawatt cogeneration facility consisting of replacement of existing boiler Nos. 1, 2, and 3 with a GE LM-6000 combustion turbine in series with a duct burner at a designed flow of 325,200 ACFM, and operating existing boiler Nos. 4 and 5 as auxiliary units.

Particulate emissions shall be controlled by using clean fuels and good combustion practices. CO emissions shall be controlled by proper combustion techniques. NO_x emissions shall be controlled by steam injection.

The facility is located at the existing Central Heat Plant on the campus of the University of Florida in Gainseville, Alachua County, Florida. The UTM coordinates are 369.4 km East and 3,279.3 km North.

The source 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. FPC letter dated 11-13-91.
2. FPC letter dated 11-25-91.
3. KBN letter dated 12-2-91.
4. DER incompleteness letter dated 12-31-91.
5. FPC letter dated 1-2-92.
6. EPA letter dated 1-8-92.
7. DER letter to EPA dated 1-16-92.
8. KBN letter dated 1-30-92.
9. FPC letter to EPA dated 2-6-92.

Attachments Cont'd

10. DER letter to EPA dated 2-12-92.
11. DER letter to EPA dated 2-14-92.
12. FPC response to incompleteness dated 3-5-92.
13. FWS letter to DER dated 4-2-92.
14. EPA letter to DER dated 4-8-92.
15. KBN letter to DER dated 4-8-92.

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, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.

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), Florida Statutes, 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.

GENERAL CONDITIONS:

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

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 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

GENERAL CONDITIONS:

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 Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. 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 Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.120 and 17-30.300, F.A.C., as applicable. 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)

GENERAL CONDITIONS:

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 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:

1. Unless otherwise indicated, the construction and operation of the subject cogeneration facility shall be in accordance with the capacities and specifications stated in the application.

SPECIFIC CONDITIONS:

2. Emissions from this facility shall not exceed the limits listed below:

Pollu-tant	Source	Fuel	Basis of Limit	lbs/hr	tons/yr
NOx	Turbine	Gas	EBM*:25 ppmvd @ 15% O2	35.0	142.7
	Turbine	Oil	EBM*:42 ppmvd @ 15% O2	66.3	7.3
	D.Burner	Gas	EBM*:0.1 lb/MMBTU	18.7	24.6
SO2	Turbine	Oil	BACT:0.1% Sulfur Max.	-	-
	Boiler 4	Oil	BACT:0.1% Sulfur Max.	-	-
	Boiler 5	Oil	BACT:0.1% Sulfur Max.	-	-
VE	Turbine	Gas/Oil	Equivalent of mass EBM*	10% opacity	
	D.Burner	Gas	" " "	10% opacity	
	Boiler 4	Gas/Oil	" " "	10% opacity	
	Boiler 5	Gas/Oil	" " "	10% opacity	
CO	Turbine	Gas	BACT:42 ppmvd	38.8	158.0
	Turbine	Oil	EBA*:75 ppmvd	70.5	7.7

* EBM: Established by manufacturer
EBA: Established by applicant

3. Fuel consumption rates and hours of operation shall not exceed those listed below:

	Natural Gas			No. 2 Fuel Oil		
	M ft3/hr*	MM ft3/yr	hrs/yr*	M gal/hr*	M gal/yr	hrs/yr*
Turbine	367.9	2997.2**	8146.8**	2.9	635.1	219.0**
Duct Burner	197.7	519.5	2628.0	0	0	0
Boiler No. 4	67.0	10.1	150.0	0.5	7.6	15.2
Boiler No. 5	160.0	63.4	396.0	1.1	25.3	23.0

*Based on maximum firing rates. Units may run at lower rates for more hours within annual fuel limits.

**An additional 1.9 hours/yr operation on natural gas will be allowed for each 1.0 hour/yr that fuel oil is not burned (up to 219 x 1.9 hours/yr).

4. Before this construction permit expires, the cogeneration facility and Central Heat Plant (Boilers 4 and 5) stacks shall be sampled according to the emission limits in Specific Condition

SPECIFIC CONDITIONS:

No. 2. Annual compliance tests shall be conducted each year thereafter. Compliance tests shall be run at 100% of permitted capacity. Tests shall be conducted using the following reference methods:

NO_x: EPA Method 20
SO_2: Fuel supplier's sulfur analysis
VE: EPA Method 9
CO: EPA Method 10

5. The DER Northeast District office shall be notified at least 30 days prior to the compliance tests. Compliance test results shall be submitted to the DER Northeast District office and the Bureau of Air Regulation office within 45 days after completion of the tests. Sampling facilities, methods, and reporting shall be in accordance with F.A.C. Rule 17-2.700 and 40 CFR 60, Appendix A.

6. Within 60 days of receipt of the compliance test results, the DER Bureau of Air Regulation in Tallahassee will re-evaluate the BACT determination.

7. A continuous operations monitoring system shall be installed, operated, and maintained in accordance with 40 CFR 60.334. The natural gas, fuel oil and steam injection flows to the cogeneration turbine along with the power output of the generator shall be metered and continuously recorded. The data shall be logged daily and maintained so that it can be provided to DER upon request.

8. The permittee shall include in the initial construction adequate modules and other provisions necessary for future installation of state-of-the-art catalytic abatement or equivalent CO and NOx control systems. Following receipt of the initial compliance test results, the Department may make a revised determination of Best Available Control Technology and may require installation of such technology.

9. Boilers Nos. 1, 2 and 3 shall permanently cease operation prior to the startup of the cogeneration facility.

10. 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).

SPECIFIC CONDITIONS:

11. 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).

Issued this ______ day
of ______________, 1992

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

____
Carol M. Browner, Secretary

Best Available Control Technology (BACT) Determination
University of Florida Cogeneration Project
Alachua County

The applicant proposes to install a 43 MW cogeneration facility to replace existing boiler capacity at the University of Florida - Gainesville campus in Alachua County. The facility will consist of a General Electric LM-6000 Gas Turbine Generator exhausting through a duct-fired heat recovery steam generator which will produce steam for the University campus. The turbine and duct burner will be fired by natural gas with No. 2 fuel oil being used only as a backup fuel for the turbine.

A BACT determination is required for all regulated air pollutants emitted in amounts equal to or greater than the significant emission rates listed in Table 500-2 of Florida Administrative Code (F.A.C.) Rule 17-2.500.

Maximum annual emissions from the proposed project are listed below in tons per year:

	Gas Turbine		Duct Burner	Total	Offsets	Increase	PSD
	NG	Oil	NG				
NO_x	142.7	7.3	24.6	174.6	134.9	39.7	40.0
SO_2	4.3	21.6	0.7	26.6	36.1	-9.5	40.0
PM/PM_{10}	10.2	1.1	2.5	13.8	3.4	10.4	25/15
CO	158.0	7.7	24.6	190.3	20.4	169.9	100.0
VOC	6.5	0.4	10.6	17.5	1.1	16.4	40.0
H_2SO_4	0.3	2.0	0.1	2.4	0.8	1.6	7.0

Emissions are based on firing natural gas in the turbine for 8,147 hours/yr at 348 MMBTU/hr and natural gas in the duct burner for 2,628 hours/yr at 187 MMBTU/hr. Oil firing in the turbine is based on 219 hours/yr at 382.6 MMBTU/hr.

Turbine performance under natural gas firing is based on NO_x emissions of 25 ppmvd (corrected to 15 percent O2). Performance on oil firing is based on NO_x emissions of 42 ppmvd (corrected to 15 percent O2). SO_2 emissions are based on 0.5 percent sulfur.

Date of Receipt of a Complete Application

March 6, 1992

BACT Determination Requested by Applicant

Control Technology: Combustion efficiency for cogeneration CO control.

Emission Limits:	75 ppmvd CO (natural gas or No. 2 oil - 0.5% Sulfur max.) (No request made for Boilers 4 and 5)

BACT Determined by the Department

Control Technology: Combustion efficiency for cogeneration CO control with provision for future installation of an oxidation catalyst system.

Emission Limits:	Turbine - natural gas firing:	42 ppmvd CO
	Turbine - No. 2 oil firing:	75 ppmvd CO
	Maximum % Sulfur - No. 2 oil:	0.1 % S
	Duct Burner - Natural gas:	0.1 lb CO/MMBTU
	Boilers 4 & 5:	10% opacity

BACT Determination Procedure

In accordance with F.A.C. Chapter 17-2, 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 control methods, systems and techniques. In addition, the regulations require 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 determinations 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.

A review of EPA's BACT/LAER Clearinghouse indicates that catalytic oxidation is the most stringent control technique. An oxidation catalyst control system allows unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F and reaches near completion (above 90%) at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than for thermal oxidation thus reducing the thermal energy required. The oxidation catalyst is typically located directly after the turbine or as an integral part of the steam generator. Catalyst size depends on the exhaust flow, temperature, and desired efficiency.

Catalytic oxidation for CO control has been employed in nonattainment areas and is considered to be LAER technology capable of reducing CO emissions to the 10 ppm range. Due to economics, applications of catalytic oxidation technology have thus far been limited to small cogeneration facilities burning natural gas. Oxidation catalysts have not been used on base-loaded fuel oil-fired turbines in simple cycle or combined cycle facilities since extended use of sulfur-containing fuel would result in increased corrosion.

Also, trace metals in the fuel could poison catalysts during prolonged fuel oil firing. For these reasons, if catalytic oxidation is required upon re-evaluation of the BACT, the permit will be amended to allow natural gas firing only.

Using the applicant's proposed CO emission level of 75 ppmvd, the total annualized cost of CO catalytic oxidation for this project is $508,156 with a cost effectiveness of about $1,970/ton of CO removed. The cost effectiveness is based on 87% efficiency (75 ppmvd to 10 ppmvd) and includes a heat rate penalty of 0.2% based on an energy loss of $50/MW associated with pressure drop across the catalyst. A review of previous BACT determinations indicates that $1,970/ton would not be prohibitive. However, the decision to require catalytic oxidation should be based on a cost/benefit analysis once compliance testing has been done, with the provision for future installation being made a condition of the original construction permit. Therefore, the Department will propose initial BACT emission limits for CO consistent with recent BACT determinations for similar sources. These limits are to be revised, if necessary, upon evaluation of the compliance test data. The turbine limit proposed by the applicant for fuel oil operation (75 ppmvd) is more stringent than a recent BACT determination for similar sources (78 ppmvd).

Other Air Pollutants Not Subject to BACT Determination

The application indicates that emissions of other pollutants will not be subject to a BACT determination. Since the applicant narrowly escaped PSD review for NO_x by lowering firing rates, and since increased firing rates may be requested at some future date, the Department will require that the applicant make provisions for future installation of state-of-the-art catalytic abatement technology for control of NO_x emissions, such as would presently be required if the source was subject to a NO_x BACT determination.

Details of the Analysis May be Obtained by Contacting:

Preston Lewis, P.E., BACT Coordinator
Department of Environmental Regulation
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	Carol M. Browner, Secretary Dept. of Environmental Regulation
______________________1992 Date	______________________1992 Date

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION IV
345 COURTLAND STREET, N.E.
ATLANTA, GEORGIA 30365

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APR - 8 1992

Clair H. Fancy, P.E., Chief
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RE: University of Florida Cogeneration Project (PSD-FL-181)

Dear Mr. Fancy:

This is in response to your letter dated January 16, 1992, which requested assistance in determining the amount of creditable reductions of NO_x emissions which are available from the existing central Heat Plant at the above referenced facility. At issue is the proper use of an AP-42 emission factor for gas/oil fired boilers larger than 100 mmBTU/hr heat input capacity.

The applicant requested that FDER use the discretion allowed under F.A.C., Rule 17-2.100(3)(b) to presume that their actual boiler emissions were equal to the allowable emissions which were based on full load operation. EPA's position on this presumption is stated in the preamble to the August 7, 1980, promulgation of federal Prevention of Significant Deterioration (PSD) regulations at 45 FR 52718:

> "EPA believes that, in calculating actual emissions, emission allowed under federally enforceable source-specific requirements should be presumed to represent actual emissions levels. Source-specific requirements include permits that specify operating conditions for an individual source, such as PSD permits, state NSR permits issued in accordance with Section 51.18(j) and other Section 51.18 programs, including Appendix 5 (the offset Ruling), and SIP emissions limitations established for individual sources. <u>The presumption that federally-enforceable source-specific requirements correctly reflect actual operating conditions should be rejected by EPA or a state, if reliable evidence is available which shows that actual emissions differ from the level established in the SIP or the permit."</u>
> (emphasis added)

From the operating reports submitted by the applicant, it is clear that the units in question did not operate at their allowable limits on a yearly average. Consequently, we concur with your determination that permitted allowable emissions are not equivalent to actual emissions for this source and that an estimation of actual emissions must be made.

In an ideal scenario, the applicant would have test data for each boiler at various load conditions along with the hours each boiler operated at the corresponding load in each year. This data would allow for the most accurate calculation of actual emissions during the years in question.

Absent having available or obtaining test data for the specific boilers, the next most accurate method for estimating actual emissions would be to utilize an established emission factor along with available fuel use data. The NO_x emission factor for gas fired boilers found in Table 1.4-1 of AP-42 requires the use of an emission factor adjustment (Figure 1.4-1) for reduced loads in boilers with a heat input capacity of greater than 100 mmBTU/hr. The applicant has argued that the emissions factor adjustment for load should only be applied on an instantaneous basis and should not be used where long-term averaging is involved.

As stated in your February 14, 1992, letter to EPA, your staff have "[f]ound data showing that, for natural gas-fired boilers, NO_x emissions are generally reduced by percentages equal to or greater than the percent load reduction." This point is confirmed in the position taken by EPA's Office of Air Quality Planning and Standards in a January 8, 1992, letter from Mr. Ron Ryan to Mr. John Reynolds of your staff. The letter stated that "[t]he load reduction coefficient determined from Figure 1.4-1 of AP-42 should be used in conjunction with the utility boiler factors in Table 1.4-1 to estimate emissions accurately." The letter further states that "[i]f estimates were made for several representative periods and summed, the result would be more accurate than using a single average load for the entire period." Note that at no time is it stated that the load reduction coefficient should be disregarded if a single average load is utilized.

As a result, the methods of estimation of actual emissions in order of their relative accuracy are as follows:

1. Stack tests at various loads along with records of hours operated at corresponding loads;

2. AP-42 emissions factors (with load reduction coefficient) along with records of hours operated at corresponding loads;

3 AP-42 emission factors (with load reduction coefficient) along with a single average load;

4. AP-42 emissions factors (without load reduction coefficient) and an assumption that the unit operated at full load.

To date, the applicant has not submitted data corresponding to stack tests or representative periods of load reduction; therefore, options 1 and 2 are not available. Your staff, in a letter to Florida Power dated December 31, 1991, determined that option 3 would provide a more accurate estimation of actual emissions than the option proposed by the applicant (option 4).

Based on the lack of data available from the applicant, the material submitted by your staff, as well as the position taken by OAQPS, we fully support your determination that in this instance, the use of a single average load factor along with corresponding emission factors (and corrections) from AP-42 would constitute representative actual emissions for the purpose of netting.

For reasons of expediency, Florida Power, in their letter to you dated March 5, 1992, has agreed to calculate actual emissions consistent with your determination. We apologize for any inconvenience caused by the delay in our response; however, based on the available information, we are confident that your determination was the correct one for this case.

If you have any questions or comments on this issue, please contact Mr. Gregg Worley of my staff at (404)347-5014.

Sincerely yours,

Shelley L. Shaver, for
Jewell A. Harper, Chief
Air Enforcement Branch
Air, Pesticides and Toxics
Management Division

cc: Ron Ryan, OAQPS
J. Reynolds
C. Holladay
A. Kutyna, NE Dist
S. Baruch, NE Dist. Branch
C. Shaver, NPS
LHF/13A/PL
K. Kosky, KBN

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Department of Environmental Regulation

Routing and Transmittal Slip

To: (Name, Office, Location)

1. Mrs. Chris Shaver
2. NPS -
3.
4.

Remarks:

FYI

FL Power Corp./U. of FL Cogen.

PSD-FL-181

From	Date
C. H. Fancy	4-8-92
	Phone 904-488-1344

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ls	From Ken Kosky
	Co. KBN
)	Phone #
9	Fax # 904-331-9000

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KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

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State of Florida
Department of Environmental Regulation

District Routing Slip

To: Andy Kutyna Date: 4-8-92

			C.C. To:
	Pensacola	**Northwest District**	
	Panama City	Northwest District Branch Office	
	Tallahassee	Northwest District Branch Office	
	Apalachicola	Northwest District Satellite Office	
	Tampa	**Southwest District**	
	Punta Gorda	Southwest District Branch Office	
	Bartow	Southwest District Satellite Office	
	Orlando	**Central District**	
	Melbourne	Central District Satellite Office	
X	**Jacksonville**	**Northeast District**	
	Gainesville	Northeast District Branch Office	
	Fort Myers	**South District**	
	Marathon	South District Branch Office	
	West Palm Beach	**Southeast District**	
	Port St. Lucie	Southeast District Branch Office	

Reply Optional ☐ Reply Required ☐ Info Only ☐
Date Due ______ Date Due: ______

Comments:

FPC / U. of FL Cogen
AC 01-204652
PSD-FL-181

From: C. H. Fancy Tel.: SC/278-1344

10-31-90

al memo 7671 | # of pages ▸ 23
From Ken Kosky
Co. KBN
Phone #
Fax # 904-331-9000

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KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

E PA
Region IV
Atlanta

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To: (Name,

1. Jewell A. Harper
2. U.S. EPA, Region IV
3.
4.

Remarks:

FYI
FL Power Corp/U. of FL Cogen.
PSD-FL-181

attn: Gregg Worley

From	Date
C. H. Fancy	4-8-92
	Phone 904-488-1344

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	Co. KBN
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KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

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KBN

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To John Reynolds	From Ken Kosky
Co. FDER	Co. KBN
Dept. 91062-0100	Phone #
Fax # 922-6979	Fax # 904-331-9000

April 8, 1992

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

Subject: Alachua County - A.P.
UF Cogeneration Project
AC 01-204652
PSD-FL-181

Attention: John Reynolds

Dear John:

As we discussed yesterday, I have summarized the last five years of fuel usage for the University of Florida's Central Heat Plant. This summary is presented in Table 1 and is based on fuel usage obtained from the Annual Operating Reports (AORs). I have attached the 1991 and 1987 fuel AORs; the 1988-90 AORs have been previously included in the air permit application.

Table 1 presents the total fuel use and the percent difference from the 5-year average. Since the Central Heat Plant is affected by meteorological conditions, a five year average is more appropriate in determining the "representative" fuel use. As can be noticed from Table 1, the natural gas fuel usage (the primary fuel) was quite different for the years 1988 and 1990. The natural gas fuel use in 1988 was 14.4 percent more than the five year average, while the fuel use in 1990 was 14.2 percent less than the five year average. This difference cancelled out in our use of the 1988 through 1990 average as being "representative" of actual emissions. Indeed, the 1988-90 average was less than 1 percent different than the five year average. Clearly, an average of the last two years (1990-91) and an average of the last three years (1989-91) are not "representative" of fuel use and therefore emissions. The percent difference for these two averaging periods is greater than several percent.

For fuel oil firing (the standby fuel), fuel use varied considerably. However, fuel oil is less important due to its total contribution to heat input. The averaging period presented in the application (i.e., 1988-90) is less than the five year average.

It should be emphasized that the definition of "actual emissions" found in Rule 17-2.100 (3) F.A.C. specifically allows the use of different time periods than the last two years if it is more representative of normal operation. Indeed, the definition expressly uses the terms "In general" and "representative" in providing guidance in determining actual emission. The subsequent paragraph expressly allows the Department to use different time periods.

91062A1/8

KBN

It is my professional opinion that we should use the 1988-90 period as being "representative" of actual emissions. The basis for this is threefold. First, this is the averaging period for which the application was based when submitted and for which the Department did not object during the first round of completeness questions. Second, I have demonstrated that this averaging period is "representative" of normal fuel usage. Finally, the issue related to using the load correction factor, which centered around this data, was conceded to the Department. In fact, considerable effort was expended in submitting additional information that was based on using the Department's recommended corrections. Therefore, the 1988-90 period should be used by the Department to define "actual emissions".

Please call if you have any questions.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

cc: Scott Osbourn, FPC
W.W. Vierday, FPC
Project File
CHF / BA / PL
John Reynolds
Jewell A. Harper, EPA
Chris Shaver, NPS
Andy Kutyna, NED

4-8-92 RAm

KFK/mlb

91062A1/8
04/08/92

Table 1. University of Florida Central Heat Plant 5-Year Fuel Use

Period	Natural Gas (10^3 cf)	% Difference from 5 year Average	Fuel Oil (gal.)	% Difference from 5 year Average
1987	1,153,937	-1.88%	20,606	-172.20%
1988	1,357,653	14.36%	604,546	74.65%
1989	1,175,617	-0.02%	163,729	-51.03%
1990	1,020,301	-14.16%	6,446	-190.87%
1991	1,171,521	-0.37%	584,213	71.69%
88-90 Average	1,184,524	0.74%	258,240	-6.62%
90-91 Average	1,095,911	-7.03%	295,330	6.80%
87-91 Average	1,175,806	0.00%	275,908	0.00%
89-91 Average	1,122,480	-4.64%	251,463	-9.27%

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

DEPARTMENT OF ENVIRONMENTAL REGULATION · STATE OF FLORIDA

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 91 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 1 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida: Physical Plant Div. Bldg. 473
   Gainesville, FL 32611
4. Description of Source: Black steel stack, south end of plant

II ACTUAL OPERATING HOURS: 2,010.20 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

Best Available Copy

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

82.014 10^6 cubic feet Natural Gas ______ 10^3 Kerosene

N/A 10^3 gallons ______ Oil, ______ %S ______ tons Coal

______ 10^3 gallons Propane ______ tons Carbonaceous

______ 10^6 Black Liquor Solids ______ tons Refuse

Other (Specify type and units) ______

EMISSION RATE(S) (tons/yr)

______ Particulates ______ Sulfur Dioxide ______ Total Reduced Sulfur

______ Nitrogen Oxide ______ Carbon Monoxide ______ Fluoride

______ Hydrocarbon Other (Specify type and units) ______

METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

II CERTIFICATION:

hereby certify that the information given in this report is correct to the best of my owledge.

______ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

______ TYPED NAME AND TITLE

______ DATE

STATE OF FLORIDA

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DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396 6959

DEPARTMENT OF ENVIRONMENTAL REGULATION STATE OF FLORIDA

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 91 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 2 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida: Physical Plant Div. Bldg. 473
   Gainesville, FL 32611
4. Description of Source: Black steel stack second from south end of plant

II ACTUAL OPERATING HOURS: 4,202.09 hrs/day ________ days/wk ________ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

173.630 10^6 cubic feet Natural Gas _______ 10^3 Kerosene

N/A 10^3 gallons _______ Oil, _______ %S _______ tons Coal

_______ 10^3 gallons Propane _______ tons Carbonaceous

_______ 10^6 Black Liquor Solids _______ tons Refuse

Other (Specify type and units) _______________________________

EMISSION RATE(S) (tons/yr)

_______ Particulates _______ Sulfur Dioxide _______ Total Reduced Sulfur

_______ Nitrogen Oxide _______ Carbon Monoxide _______ Fluoride

_______ Hydrocarbon Other (Specify type and units) _______________

METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

I CERTIFICATION:

ereby certify that the information given in this report is correct to the best of my wledge.

_______________________________ _______________________________
SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE TYPED NAME AND TITLE

____
DATE

Best Available Copy

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396-6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1991 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 3 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida, Physical Plant Div. Bldg. 473
   Gainesville, FL 32611
4. Description of Source: Black steel stack center of plant

II ACTUAL OPERATING HOURS: 5,371.60 hrs/day ________ days/wk ________ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 120,000 lbs per hour

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

287.180 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

129.151 10^3 gallons 6 Oil, 1.5 %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________________

I EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units)________________________

II METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visiable emission is 8.4 percent opacity. The highest six-minute average was 10.6 percent.

III CERTIFICATION:

hereby certify that the information given in this report is correct to the best of my knowledge.

________________________ ________________________
SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE TYPED NAME AND TITLE

____
DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396 6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1991 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 4 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida, Physical Plant Div. Bldg. 473
   Gainesville, FL 32611
4. Description of Source: Black steel stack second from north end of plant

II ACTUAL OPERATING HOURS: 4,091.30 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 50,000 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

134.723 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

71.254 10^3 gallons 6 Oil, 1.5 %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________________________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 10 percent opacity. The highest six-minute was 0 percent.

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

________________________________ ________________________________

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE TYPED NAME AND TITLE

____

DATE

Best Available Copy

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396 6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 91 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 5 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida; Physical Plant Div. Bldg. 473
   Gainesville, FL 32611
4. Description of Source: Black steel stack north end of plant

II ACTUAL OPERATING HOURS: 5,294.30 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other then tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

______

______

______

______

Best Available Copy

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

493.974 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

383,808 10^3 gallons ____6__ Oil, __1.5__ %S ________ tons Coal

______ 10^3 gallons Propane ________ tons Carbonaceous

______ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ____

EMISSION RATE(S) (tons/yr)

__________ Particulates __________ Sulfur Dioxide __________ Total Reduced Sulfur

__________ Nitrogen Oxide __________ Carbon Monoxide __________ Fluoride

__________ Hydrocarbon Other (Specify type and units)______________________

I METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 wased used a described in 40 cfr 60, appendix A. The visible emission limit is 10 percent opacity. The highest six-minute average was 1.3 percent.

III CERTIFICATION:

hereby certify that the information given in this report is correct to the best of my owledge.

________________________________ ________________________________

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE | TYPED NAME AND TITLE

____

DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396-6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 87 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 1 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida, Physical Plant Division Building 473, Gainesville, Florida 32611
4. Description of Source: Black Steel stack south end of plant

II ACTUAL OPERATING HOURS: 651 hrs/~~day~~ ____ days/wk ____ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60, 000 lbs per hour

Best Available Copy

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

26.673 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

0 10^3 gallons #6 Oil, 2 %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________________________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________________________________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

NOT TESTED

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

Ken Kisida

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

Ken Kisida, Utilities Manager

TYPED NAME AND TITLE

February 19, 1988

DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396-6959

DEPARTMENT OF ENVIRONMENTAL REGULATION
STATE OF FLORIDA

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 87 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 2 Steam boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida, Physical Plant Division, Building 473 Gainesville, Florida 32611
4. Description of Source: Black Steel stack second from south end of plant

II ACTUAL OPERATING HOURS: 2319 hrs/~~day~~ ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

Best Available Copy

V **TOTAL FUEL USAGE** including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

93.48 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

0 10^3 gallons #6 Oil, 2 %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ____________________

VI **EMISSION RATE(S)** (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ____________________

VII **METHOD OF CALCULATING EMISSION RATES** (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

NOT TESTED

VIII **CERTIFICATION:**

I hereby certify that the information given in this report is correct to the best of my knowledge.

Ken Kisida
SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

Ken Kisida, Utilities Manager
TYPED NAME AND TITLE

February 19, 1988
DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396-6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 87 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 3 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida, Physical Plant Division, Building 473
   Gainesville, Florida 32611
4. Description of Source: Black Steel stack center of the plant

II ACTUAL OPERATING HOURS: 2622 hrs/~~day~~ ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 120,000 lbs per hour

Best Available Copy

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

199.013 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

16.823 10^3 gallons #6 Oil, 2 %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________

I EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________________

II METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA Method 9 was used as described in 40 CFR 60, Appendix A. The visible emission limit is 20 percent opacity. The highest six-minute average was 13.3 percent.

III CERTIFICATION:

hereby certify that the information given in this report is correct to the best of my knowledge.

Ken Kisida

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

Ken Kisida, Utilities Manager

TYPED NAME AND TITLE

February 19, 1988

DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396-6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 87 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 4 Steam boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida, Physical Plant Division, Building 473
   Gainesville, Florida 32611
4. Description of Source: Black steel stack second from north end of plant.

II ACTUAL OPERATING HOURS: 6265 hrs/~~day~~ ____ days/wk ____ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 50,000 lbs per hour

Best Available Copy

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

274.886 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

0.272 ____ 10^3 gallons #6 Oil, 2 %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________________________

I EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________________

II METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA Method 9 was used as described in 40 CFR 60, Appendix A. The visible emission limit is 20 percent opacity. The highest six-minute average was 5.4 percent.

III CERTIFICATION:

hereby certify that the information given in this report is correct to the best of my nowledge.

Ken Kisida

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

Ken Kisida, Utilities Manager

TYPED NAME AND TITLE

February 19, 1988

DATE

BEST AVAILABLE COPY

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT

3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396-6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST L. FREY
DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1987 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 5 Steam boiler
2. Permit Number: A001-57683
3. Source Address: University of Florida, Physical Plant Division, Building 473
   Gainesville, Florida 32611
4. Description of Source: Black Steel stack on north end of plant.

II ACTUAL OPERATING HOURS: 6766 hrs/~~day~~ ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

steam at 120,000 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

Best Available Copy

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

559,855 10^6 cubic feet Natural Gas ______ 10^3 Kerosene

3.511 10^3 gallons #6 oil, 2 %S ______ tons Coal

______ 10^3 gallons Propane ______ tons Carbonaceous

______ 10^6 Black Liquor Solids ______ tons Refuse

Other (Specify type and units) ______________________

I EMISSION RATE(S) (tons/yr)

______ Particulates ______ Sulfur Dioxide ______ Total Reduced Sulfur

______ Nitrogen Oxide ______ Carbon Monoxide ______ Fluoride

______ Hydrocarbon Other (Specify type and units) ______________________

II METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 CFR 60, Appendix A. The visible emission limit is 20 percent opacity. The highest six-minute average was 1.3 percent.

III CERTIFICATION:

hereby certify that the information given in this report is correct to the best of my nowledge.

Ken Kisida

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

Ken Kisida, Utilities Manager

TYPED NAME AND TITLE

February 19, 1988

DATE

BEST AVAILABLE COPY

Department of Environmental Regulation

Routing and Transmittal Slip

To: (Name, Office, Location)

1. Ms. Jewell A. Harper
2. U.S. EPA, Region IV
3.
4.

Remarks:

PSD-FL-181

FL Power Corp / U. of FL. Cogen.

attn: Gregg Worley

From: C. H. Fancy

Date: 4-7-92

Phone: 904-488-1344

Interior TAKE PRIDE IN AMERICA

ECEIVED

APR 6 1992

Division of Air
:sources Management

sent us regarding
.ruct a cogeneration
. Heat Plant. The
ıximately 100 km
ı0 km south of the
:reas administered by

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1, 2, and 3, and that
for the new turbine.
: are subtracted from
project will result
;, a small increase in
volatile organic
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the proposed emission
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ıodeling analysis
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.s operated in this
manner, we do not anticipate that the University of Florida project will have a significant impact on sensitive air quality-related resources in the Chassahowitzka or Okefenokee Wilderness Areas.

File Copy
PSD-FL-181

United States Department of the Interior

TAKE PRIDE IN AMERICA

FISH AND WILDLIFE SERVICE
75 Spring Street, S.W.
Atlanta, Georgia
30303

April 2, 1992

RECEIVED
APR 6 1992
Division of Air
Resources Management

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

Dear Mr. Fancy:

We have completed our review of the material that you sent us regarding Florida Power Corporation's (FPC) application to construct a cogeneration facility at the existing University of Florida Central Heat Plant. The University of Florida is located in Gainesville, approximately 100 km northeast of the Chassahowitzka Wilderness Area and 100 km south of the Okefenokee Wilderness Area, both class I air quality areas administered by the Fish and Wildlife Service.

We understand that FPC is proposing to install a single natural gas-fired combustion turbine that will replace existing boilers 1, 2, and 3, and that existing boilers 4 and 5 will only be used as back-up for the new turbine. When the emission reductions from the existing boilers are subtracted from the emission increases from the proposed turbine, the project will result in a significant increase in carbon monoxide emissions, a small increase in emissions of particulate matter, nitrogen oxides, and volatile organic compounds, and a slight decrease in sulfur dioxide emissions.

We were pleased to see that FPC modeled the impact of the proposed emission increases of nitrogen oxides and particulate matter on both the Chassahowitzka and Okefenokee Wilderness Areas. The modeling analysis indicates that the proposed project would have a negligible impact on the class I areas. We recommend that you draft a permit condition requiring FPC to permanently shut down existing boilers 1, 2, and 3 as soon as the new turbine is operational. As long as the facility is operated in this manner, we do not anticipate that the University of Florida project will have a significant impact on sensitive air quality-related resources in the Chassahowitzka or Okefenokee Wilderness Areas.

We appreciate the opportunity to comment on FPC's permit application. If you have any further questions regarding our comments on this project, please contact Tonnie Maniero of our Air Quality office in Denver at 303/969-2071.

Sincerely yours,

James W. Pulliam, Jr.
Regional Director

CHF/BA/PL
John Reynolds
Clene Holladay
Jewell A. Harper, EPA
Andy Kutyna

4-7-92 RAM

Florida Power
CORPORATION

RECEIVED

MAR 6 1992

Bureau of
Air Regulation

March 5, 1992

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

Subject: Alachua County - A.P.
UF Cogeneration Project
AC 01-204652

Dear Clair:

This correspondence provides responses to your letter dated December 31, 1991 as well as revising our application in light the Department's position on the emission factors for load. The responses are presented in the same format as those of your December 31, 1991 letter.

Item 1.

The AP-42 NO_x emission factor for fully loaded natural gas-fired boilers over 100 MMBtu/hr is 550 lbs. NO_x/MM ft^3 of fuel fired. For loads less than 100%, the emission factor is reduced according to AP-42, Figure 1.4-1. The 100% factor was used to calculate offset credits of 195.1 tons/yr of NO_x emissions, thus arriving at a net NO_x increase of 38.8 tons/yr. This level of net emissions (less than 40 tons/yr) would preclude PSD review for NO_x as stated in the application. However, analysis of load factors for UF's boilers Nos. 3 and 5 (capacity over 100 MMBtu/hr) during the three period '88 - '90 indicates otherwise.

FPC Response:

The basis of the application has been revised according to the comments made in the Department's December 31, 1991 letter and subsequent correspondence and discussions. Section 2.0 of the PSD permit application has been revised to reflect lower nitrogen oxides (NO_x) emissions from the combustion turbine and duct burner, and further fuel use reductions in Boilers 4 and 5 in the future. These reductions reduce the net emissions increase of NO_x, as well as particulate matter and PM10, to below the significant emission rates in Table 500-2 of Rule 17-2 F.A.C. The following is a description of the changes made from the original application.

Item 1

FPC Response (continued)

a. The capacity factors on the combustion turbine (CT) and duct burner (DB) were reduced. The capacity factor for the CT when firing oil was reduced from 5 percent (438 hours per year at full load) to 2.5 percent (219 hours per year at full load). The capacity factor for firing natural gas in the CT when the maximum oil firing occurs, has been reduced from 95 percent to 93 percent. The application has requested the Department to allow 1.9 hours of natural gas firing for each hour in a given year that oil is not fired at its maximum permitted rate. This would allow up to a 97.75 percent capacity factor for natural gas firing in any year where oil is not fired. The capacity factor for the duct burner has been reduced from 90 percent to 30 percent. Section 2.2 and Tables 2-1 and 2-2 provide a detailed description of the change.

   With these revisions, the potential NO_x emissions for the CT/DB are 174.6 tons per year (see Table 2-2). Emissions of other pollutants are also reduced.

b. The NO_x emission factors for Boilers 3 and 5 were revised to be consistent with those calculated by the Department. While we still have technical reservations about using the load correction figure, it is expedient for us to accept the approach based on the needs of the project. It should be recognized by the Department that sufficient information to accurately calculate emissions using this approach does not exist, and previous applications (as well as annual operating reports) did not use this approach.

   Tables 2-3 and 2-4 have been revised to reflect the Department's emission factor.

   Table 2-5 has been revised to reduce the maximum fuel usage in Boilers 4 and 5. The maximum natural gas and distillate fuel oil usage for Boiler 4 has been reduced from 75 MM ft^3/year and 25,000 gallons/year, respectively to 20 MM cf/year and 15,000 gallons/year. Similarly, the fuel use in Boiler 5 has been reduced from 210 MMcf of gas per year and 100,000 gallons of oil per year to 125 MMcf of gas per year and 50,000 gallons of oil per year.

   The net NO_x emission reductions from the existing boilers are: 72.2 tons per year from Boilers 1, 2 and 3, and 62.7 tons per year from Boilers 4 and 5 (actual emissions of 82.43 tons per year minus future emissions of 19.73 tons per year). (See Table 2-6 for all net emission reductions.)

Item 2.

References in the application to the proposed facility being major on the basis of emissions exceeding 250 tons per year should be changed to 100 tons per year since the HRSG is on the "List of 28" major source categories (fossil fuel boiler exceeding 250 MMBtu/hr input including GT exhaust).

FPC Response:

The PSD applicability section of the report (i.e., 3.4) has been revised and is attached. The net emissions increase for NO_x is the potential emissions from the project of 174.6 tons per year minus the emission reductions of 134.9 tons per year, or 39.7 tons per year.

Item 3.

Page 2 of Form 1.202(1), Item C., implies "low NO_x combustors" are being proposed which is not the case. The revised application should explain that Low-NO_x combustors are not currently available for this model turbine but may be within 5 years. The revision should explain what is required in the initial design to provide for future installation of Low-NO_x burners.

FPC Response:

The comment incorrectly assigns meanings to the statements made on page 2 item C of FDER Form 17-1.202(1). The form explicitly uses the language "low NO_x combustors using wet injection". The implication here is that a specially designed combustor using wet injection (i.e., steam) will control NO_x emission. This should not be confused with dry low NO_x combustors which use staged combustion to control NO_x emissions. Dry low NO_x combustors are not available for the aircraft- derivative GE LM 6000 combustion turbine proposed for the project. Inquiries with GE have indicated that a dry low NO_x combustor for this model may be available in mid-1995. Indications are that it may be possible to install this low NO_x combustor on existing machines with a major overhaul. However, the target NO_x emission level is 25 ppmvd corrected to 15 percent oxygen which is the same as that proposed for the project.

Item 4.

Emission calculations are not adequately shown in Appendix A. All calculations affecting emissions should be shown in their entirety. For example, the Appendix "A" calculation for the NSPS NO_x emission limit of 75 ppm corrected to 15 percent oxygen is not carried to completion. The application should clearly show how all emission-related quantities were obtained.

The bases for all calculations are presented in a revised Appendix A. This format has been used and accepted by FDER on previous projects (at least three other projects).

Item 5.

Total steam production should be shown in Table 1-1 along with design capacity of the HRSG.

Total steam production is irrelevant to the air pollutant emissions and NSPS and PSD applicability. Nonetheless, the average steam production when the facility will begin operation in 1994 will be 112,500 lb/hr.

Item 6.

Please evaluate the impact of this project on the following Class I areas: Chassahowitzka National Wilderness Area in Florida and Okefenokee National Wilderness Area in Georgia. This evaluation should include a cumulative PM_{10} and NO_x Class I increment analysis. An expanded air quality related values analysis (AQRV) should be done since there are no significant impact levels for this analysis. The AQRV analysis includes impacts to soils, vegetation and wildlife.

Although the proposed permit revision does not trigger PSD review for PM/PM10 and NO_x, the proposed project's PM and NO_x emissions were evaluated at both the Chassahowitzka Wilderness Area (CWA) and the Okefenokee Wilderness Area (OWA). The results for CWA and OWA are summarized in Tables 1 and 2, respectively, for a generic facility emission rate of 10 g/s. The actual PM and NO_x concentrations are compared with suggested Class I significant impact levels (ref: EPA memorandum from John Calcagni dated 9/10/91) for each area in Table 3.

At the CWA, the maximum annual and 24-hour PM concentrations are 0.001 and 0.031 $\mu g/m^3$, respectively. These concentrations are well below the respective Class I significant impact levels of 0.27 and 1.35 $\mu g/m^3$. The maximum NO_x concentration is 0.002 $\mu g/m^3$ which is well below the Class I significant impact level of 0.1 $\mu g/m^3$.

At the OWA, the maximum annual and 24-hour PM concentrations are 0.001 and 0.034 $\mu g/m^3$, respectively. These concentrations are well below the respective Class I significant impact levels of 0.27 and 1.35 $\mu g/m^3$. The maximum NO_x concentration is 0.0025 $\mu g/m^3$ which is well below the Class I significant impact level of 0.1 $\mu g/m^3$.

Based on these analysis, the proposed project is considered to have a negligible impact upon these Class I areas. Therefore, cumulative modeling and AQRV analyses for these areas are not required.

Item 7.

Please explain the use of terrain elevations at receptor points in the modeling and show how the elevations input into the model were derived.

Terrain elevations were included in the impact analysis for the proposed project because the proposed facility's stack height relative to the variation in terrain elevation in the area is not considered large enough to ignore these effects and assume a flat terrain analysis.

The elevations used for the receptors in the modeling analysis were derived from USGS topographical maps of the site vicinity and represent the maximum elevations within a particular screening receptor sector. A receptor's sector includes the area around the receptor up to half the distance to all adjacent receptors, both radially and azimuthally. For the elevations for the furthest receptor ring, the areas to be included beyond that distance are taken to be equal to half the distance between that ring and the next closest ring.

If you should have any questions or require clarification of the above, please contact Mr. Scott Osbourn of my staff at (813) 866-5158.

Sincerely,

W. Jeffrey Pardue, Manager
Environmental Programs

Enclosure

cc: File (2)

bb:\SHO\University of FL Project

cc: J. Reynolds
C. Holladay
A. Kutyna, NE Dist
S. Beruch, NE Dist. Branch
J. Harper, EPA
C. Shaver, NPS

Table 1. Maximum Predicted Impacts for the Proposed UF Cogeneration Facility At the Chassahowitzka Wilderness Area Using a Generic Emission Rate of 10 g/s

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor Location[a] X (m)	Receptor Location[a] Y (m)	Day/ Period
Annual					
	1983	0.007	341100	3183400	- / -
	1984	0.009	341100	3183400	- / -
	1985	0.007	342400	3180600	- / -
	1986	0.007	343700	3178300	- / -
	1987	0.008	341100	3183400	- / -
1-Hour[b]					
	1983	2.366	336500	3183400	159/21
	1984	2.754	341100	3183400	286/ 6
	1985	2.303	334000	3183400	238/23
	1986	2.262	339000	3183400	237/22
	1987	2.961	343700	3178300	199/ 5
3-Hour[b]					
	1983	0.923	342400	3180600	272/ 7
	1984	1.036	339000	3183400	164/ 8
	1985	0.768	334000	3183400	238/ 8
	1986	0.920	336500	3183400	289/ 7
	1987	0.987	343700	3178300	199/ 2
8-Hour[b]					
	1983	0.451	342400	3180600	288/ 1
	1984	0.459	341100	3183400	286/ 1
	1985	0.377	342400	3180600	306/ 3
	1986	0.626	339000	3183400	237/ 3
	1987	0.489	343700	3178300	199/ 1
24-Hour[b]					
	1983	0.170	342400	3180600	288/ 1
	1984	0.176	341100	3183400	286/ 1
	1985	0.154	343700	3178300	292/ 1
	1986	0.244	339000	3183400	237/ 1
	1987	0.178	343700	3178300	199/ 1

[a] UTM Coordinates
[b] All short-term concentrations indicate highest concentrations.

Table 2. Maximum Predicted Impacts for the Proposed UF Cogeneration Facility At the Okefenokee Wilderness Area Using a Generic Emission Rate of 10 g/s

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor Location[a] X (m)	Receptor Location[a] Y (m)	Day/ Period
Annual					
	1983	0.007	366000	3384000	- / -
	1984	0.008	383000	3382000	- / -
	1985	0.011	380000	3382000	- / -
	1986	0.009	366000	3384000	- / -
	1987	0.008	378000	3382000	- / -
1-Hour[b]					
	1983	2.328	380000	3382000	136/ 3
	1984	2.954	376000	3382000	100/20
	1985	2.349	380000	3382000	192/ 1
	1986	2.344	380000	3382000	267/24
	1987	2.974	366000	3384000	110/22
3-Hour[b]					
	1983	1.159	374000	3383000	193/ 8
	1984	1.278	390000	3410000	187/ 1
	1985	1.361	380000	3382000	233/ 2
	1986	1.303	366000	3384000	189/ 8
	1987	1.197	378000	3382000	154/ 2
8-Hour[b]					
	1983	0.552	374000	3383000	319/ 1
	1984	0.639	390000	3410000	187/ 1
	1985	0.831	380000	3382000	233/ 1
	1986	0.560	383000	3382000	220/ 1
	1987	0.623	368000	3383000	253/ 1
24-Hour[b]					
	1983	0.181	374000	3383000	193/ 1
	1984	0.216	368000	3383000	188/ 1
	1985	0.259	376000	3382000	56/ 1
	1986	0.206	366000	3384000	189/ 1
	1987	0.267	390000	3384000	354/ 1

[a] UTM Coordinates
[b] All short-term concentrations indicate highest concentrations.

Table 3. Maximum Predicted Pollutant Impacts of the Proposed Facility Compared to Recommended PSD Class I Significant Impact Levels

Pollutant	Averaging Period	Emission Rate (lb/hr)	Generic Impact (μg/m)	Predicted Impact (μg/m)	Class I Significant Impact Level (μg/m)
CHASSAHOWITZKA WILDERNESS AREA					
Particulate Matter	Annual	10.0	0.009	0.001	0.27
	24-Hour		0.244	0.031	1.35
Nitrogen Oxides	Annual	66.3	0.009	0.007	0.1
OKEFENOKEE WILDERNESS AREA					
Particulate Matter	Annual	10.0	0.011	0.001	0.27
	24-Hour		0.267	0.034	1.35
Nitrogen Oxides	Annual	66.3	0.011	0.009	0.1

Note: Short-term maximum impacts are highest predicted concentrations for 1983-87.

CERTIFICATION BY A PROFESSIONAL ENGINEER REGISTERED IN FLORIDA

This is to certify that the revisions contained herein have been prepared by me and found to be consistent with my original certification.

Kennard F. Kosky
Kennard F. Kosky, P.E.
KBN Engineering and Applied Sciences, Inc.
1034 N.W. 57th Street
Gainesville, FL 32605
Fla. Registration No. 14996
(904) 331-9000

CERTIFICATION BY A PROFESSIONAL ENGINEER REGISTERED IN FLORIDA

This is to certify that the revisions contained herein have been prepared by me and found to be consistent with my original certification.

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SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable: ***Not applicable***

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		

B. Process Rate, if applicable: (See Section V, Item 1) ***Not applicable***

1. Total Process Input Rate (lbs/hr): ______

2. Product Weight (lbs/hr): ______

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary) ***See Table 2-1 in PSD Permit application***

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/hr	T/yr	
SO_2	***197.5 (CT Oil)***	***13.8***	***0.8% Sulfur***	***316.1***	***197.5***	***13.8***	***See***
PM	***10 (CT Oil)***	***26.6***	***NA***	***NA***	***10***	***26.6***	***Figure 2-1***
NO_x	***66.3 (CT Oil)***	***174.6***	***126 ppmvd***	***198.9***	***66.3***	***174.6***	***in PSD***
CO	***97.6 (CT DB)***	***326.7***	***NA***	***NA***	***97.6***	***326.7***	***Application***
VOC	***9.63 (CT DB)***	***17.5***	***NA***	***NA***	***9.63***	***17.5***	

[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) ***NSPS--0.8% sulfur oil and 75 ppmvd NO_x corrected for heat rate, i.e., 126 ppmvd; FDER Rule 17-2.660.***
[3]Calculated from operating rate and applicable standard.
[4]Emission, if source operated with~~out~~ control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4) *See Section 4.0 in PSD Application*

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 *See Table A-1 in PSD Permit Application*

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas-CT	*342,071.2 CF*[a]	*367,818.5 CF*	*348 @ Operating Conditions*
Natural Gas-DB	*59,302.3 CF*[b]	*197,674.4 CF*	*187*
Fuel Oil-CT	*1,039.6 lb*[c]	*20,792.4 lb*	*382.6 @ Operating*
			Conditions

CT = combustion turbine; DB = duct burner
*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, others--lbs/hr.
[a]*8,146.8 hr/yr when also firing oil at 219 hours per year;* [b]*2,628 hr/yr;* [c]*219 hr/yr*
Fuel Analysis:

Percent Sulfur: *NG = 1 grain/100 CF; oil = 0.5% sulfur* Percent Ash: *<0.1*

Density: *~7.2 for oil* lbs/gal Typical Percent Nitrogen: *<0.015*

Heat Capacity: *NG = 946 Btu/CF; Oil = 18,400* BTU/lb *132,480 (Oil)* BTU/gal

Other Fuel Contaminants (which may cause air pollution): *See Appendix A in PSD Permit Application*

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average ______ Maximum ______

G. Indicate liquid or solid wastes generated and method of disposal.

All wastewaters generated from the plant will be discharged to the University of Florida wastewater treatment plant.

2.0 PROJECT DESCRIPTION

2.1 GENERAL DESCRIPTION

The proposed project will consist of installing one CT and one HRSG at the UF Central Heat Plant. The UF Central Heat Plant has five existing boilers which are fired primarily with natural gas; residual oil is used as the backup fuel. The project will replace existing boilers 1, 2, and 3; Boilers 4 and 5 will be operated as backup units for the cogeneration plant. The existing boilers and cogeneration plant will be under the common control of FPC. Therefore, the "facility" for which PSD approval is requested includes the existing Central Heat Plant and the cogeneration plant. This is consistent with the term defined in Florida Department of Environmental Regulation (FDER) Rule 12-2.100(78) Florida Administrative Code (F.A.C.).

The CT will be the new General Electric (GE) LM 6000 machine. The LM 6000 is a newly developed aircraft-derivative machine with a thermal efficiency of approximately 40 percent. This efficiency, developed from advanced aircraft compressor and turbine technology, makes the LM 6000 more efficient than the advanced heavy-frame combustion turbine being offered by certain manufacturers (e.g., the GE Frame combustion turbine). A description of this machine is presented in Appendix A. The CT exhaust will go through the HRSG and exit to the atmosphere through an individual stack. There will be no bypass stack on the CT for simple cycle operation. A flow diagram of the project is presented in Figure 2-1.

The primary fuel for firing the CT will be natural gas; distillate fuel oil will be used as emergency backup when natural gas is curtailed. Operation with distillate oil will not exceed a capacity factor of 2.5 percent or 219 hours per year at full load. There will be supplementary firing of natural gas only in the HRSG.

Air emission sources associated with the proposed project consist of the CT and supplemental firing in the HRSG. Wet injection will be used to control emissions of nitrogen oxides (NO_x) from the CT. The use of natural gas or low-sulfur (0.5-percent-sulfur maximum) distillate fuel oil will minimize the emissions of sulfur dioxide (SO_2) from the unit.

2.2 FACILITY EMISSIONS AND STACK OPERATING PARAMETERS

The emissions and stack parameters for the CT are presented in Table 2-1. These data represent the maximum emissions since air inlet coolers may be installed on the CT to maintain a compressor temperature of 51°F, which will increase generating capability and regulate temperature. Maximum potential annual emissions for the project are presented in Table 2-2. Performance information and maximum emission rates for regulated criteria pollutants, regulated noncriteria pollutants, and nonregulated pollutants from the CT are presented in Tables A-1 through A-5 of Appendix A.

The maximum capacity factors for the combustion turbine will be 93 percent (8,146.8 hours per year) on natural gas and 2.5 percent (219 hours per year) on distillate oil. Because NO_x emissions when firing distillate oil are 1.9 times greater than when firing natural gas, it is requested that the up to 1.9 times more natural gas be allowed for each hour of distillate oil not burned in any given year. The fuel use restriction would be:

Natural Gas Restriction = 348 x 10^6 Btu/hour x 8,146.8 hours/year = 2,835,086 x 10^6 Btu/year <u>and</u>,

Distillate Oil = 382.6 x 10^6 Btu/hour x 219 hours/year = 83,789 x 10^6 Btu/year

<u>or</u>,

Natural Gas = 348 x 10^6 Btu/hr x (8,146.8 + 1.9 x 219 hours/year)
= 2,979,889 x 10^6 Btu/year or 97.75 percent capacity factor

Supplemental firing with natural gas will take place in the duct between the CT and the HRSG. The supplemental firing, at a maximum rate of 187 million British thermal units per hour (x 10^6 Btu/hr), will allow the HRSG to produce additional steam. The firing of natural gas will produce additional air emissions, as shown in Tables 2-1 and 2-2, for the maximum firing rate. These emissions will combine with the CT exhaust gases only during natural gas firing and exhaust through the HRSG stack. Supplemental firing will be limited to a 30 percent capacity factor or an equivalent of 2,628 hours per year at maximum capacity (i.e., 491,436 x 10^6 Btu).

2.3 EXISTING FACILITY EMISSIONS

The proposed facility will include the existing Central Heat Plant which consists of five boilers firing natural gas and residual oil. Boilers 1, 2 and 3 will be taken out of service when the cogeneration plant becomes operational. Boilers 1 and 2 have heat input capacities of 88.5 million Btu per hour. Boiler 3 has a heat input capacity of 160.6 x 10^6 Btu/hr. Boilers 4 and 5 have heat input capacities of 71.7 and 172.2 x 10^6 Btu/hr and will be used only as back-up for the cogeneration plant. The primary fuel for these boilers will be natural gas and will be operated at lower capacity factors than in previous years. The use of residual oil in these boilers will be eliminated and replaced with distillate oil. Copies of the FDER permits are contained in Appendix B.

Because the facility consists of the Central Heat Plant, the net emissions decreases are creditable when evaluating PSD applicability [FDER Rule 17-2.500(2)(e)]. For the Central Heat Plant, the actual emissions representative of operation are presented in Table 2-3 for Boilers 1, 2, and 3, and Table 2-4 for Boilers 4 and 5. These emissions represent an average of the last complete 3-years (1988-90). A 3-year average is considered representative because operation of the Central Heat Plant is affected by meteorological conditions, i.e. heating and cooling requirements. Three years were used since the calendar year 1990 was abnormally warm compared with historical data. A quantitative measure of this is reflected by the number of heating degree days observed by the National Weather Service for Gainesville. In 1990, the heating degree days were 709 compared to a historical average of 1,259. The average heating degree days for 1990 and 1989 was 974 which would normally be considered the two year period identified in the Department's rules [Rule 17-2.100(3)(a)] as applicable for calculating actual emissions. However, this period was not representative of actual emissions. Therefore, a three year average of 1988 through 1990 was used to calculate actual emissions. The heating degree days for this period is 1,104 which is more representative of the operation of the UF heating plant. Copies of the annual operation reports are contained in Appendix B.

Since Boilers 4 and 5 will be operated as backup units for the cogeneration plant, the operation of these sources will be restricted based on fuel use. The fuel use and emissions are presented in Table 2-5. Also, the emission estimates in this table reflect the use of distillate oil rather than residual oil. The elimination of Boilers 1, 2, and 3, and the restriction in fuel use and use of distillate oil in Boilers 4 and 5 will provide net emission decreases for the facility which are presented in Table 2-6.

Table 2-1. Stack, Operating, and Emission Data for the UF Cogeneration Facility (Page 1 of 2)

Parameter	Fuel Type: Fuel Oil[a] Gas Turbine	Natural Gas: Gas Turbine[b]	Natural Gas: Duct Burner[c]
Stack Data (ft)			
Height	93	93	d
Diameter	9.75	9.75	d
Operating Data			
Temperature (°F)	257	257	d
Velocity (ft/sec)	71.5	72.59	d
Building Data (ft)			
Height	57	57	d
Length	54	54	d
Width	14	14	d
Maximum Hourly Emission Data (lb/hr) for Each Emission Unit/Fuel Type			
Sulfur Dioxide	197.5	1.05	0.56
Particulate Matter	10.0	2.5	1.87
Nitrogen Oxides	66.3	35.0	18.7
Carbon Monoxide	70.5	69.5	28.1
Volatile Organic Compounds	4.03	1.59	8.04
Sulfuric Acid Mist	15.1	0.08	0.04
Lead	0.0034	Neg	Neg
Annual Potential Emission Data (TPY) for Each Emission Unit/Fuel Type			
Sulfur Dioxide	21.6	4.6	0.74
Particulate Matter	1.1	10.95	2.46
Nitrogen Oxides	7.26	153.4	24.6

Table 2-1. Stack, Operating, and Emission Data for the UF Cogeneration Facility (Page 2 of 2)

Parameter	Fuel Type		
	Fuel Oil[a]	Natural Gas	
	Gas Turbine	Gas Turbine[b]	Duct Burner[c]
Carbon Monoxide	7.72	304.4	36.9
Volatile Organic Compounds	0.44	7.0	10.6
Sulfuric Acid Mist	1.65	0.3	0.06
Lead	0.00037	Neg	Neg

Note: See Tables A-1 through A-5 in the appendix for more detail.

°F = degrees Fahrenheit.
ft = feet.
ft/second = feet per second.
lb/hr = pounds per hour.
TPY = tons per year.

[a] Performance based on nitrogen oxide emissions of 42 parts per million by volume dry (corrected to 15 percent O_2); sulfur dioxide emissions based on an average sulfur content of 0.5 percent sulfur; annual emission data based on 2.5 percent capacity factor or 219 hours per year at full load.
[b] Performance based on nitrogen oxide emissions of 25 parts per million volume dry (corrected to 15 percent O_2); annual emissions data based on 8,760 hours/year (365 days per year) operation.
[c] Performance based on 187 x 10^6 Btu/hr heat input per heat recovery steam generators and 30 percent capacity factor or 2,628 hours per year operation at full load.
[d] Same as gas turbine natural gas; duct burners will not fire No. 2 oil.

Table 2-2. Maximum Annual Potential Emissions From Proposed Cogeneration Project

Pollutant	Fuel (TPY) Distillate Oil[a]	Fuel (TPY) Natural Gas[b] Gas Turbine	Fuel (TPY) Natural Gas[b] Duct Burner	Total (TPY)
Sulfur Dioxide	21.6	4.3	0.7	26.6
Particulate Matter[c]	1.1	10.2	2.5	13.8
Nitrogen Oxide	7.26	142.7	24.6	174.6
Carbon Monoxide	7.72	282.1	36.9	326.7
Volatile Organic Compounds	0.44	6.5	10.6	17.5
Sulfuric Acid Mist	2.0	0.3	0.05	2.4
Lead	0.00034	Neg	Neg	0.00034

Note: Neg = negative.
PM10 = particulate matter with an aerodynamic diameter less than or equal to 10 micrometers.
TPY = tons per year.

[a]219 hours/year.
[b]93% capacity factor for gas turbine and 30% capacity for duct burner.
[c]PM10.

Table 2-3. Actual Representative Emissions (1988-1990) of Regulated Pollutants, Boilers 1, 2, and 3 (Page 1 of 2)

	Boilers No. 1 & 2[a]		Boiler No. 3[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Natural Gas Burned[c]					
(MM ft^3/yr)	208.099		368.275		
No. 6 Fuel Oil[c]					
(gal/yr)		0		12,519	
(% sulfur)		1.85		1.85	
Emission Factor	lb/MM scf	lb/1,000 gal	lb/MM scf	lb/1,000 gal	
Particulate Matter	3	12.64[d]	3	21.5[d]	
Particulate Matter (PM10)	3	8.97[d]	3	15.27[d]	
Sulfur Dioxide	0.6	151.3[e]	0.6	290.5[e]	
Nitrogen Oxides	140	55	310.6[f]	67	
Carbon Monoxide	35	5	40	5	
Volatile Organic Compounds (methane)	3	1	0.3	0.28	
Volatile Organic Compounds (nonmethane)	2.8	0.28	1.4	0.76	
Lead	Neg.	0.0042	Neg.	0.0042	
Fluorides	Neg.	0.052	Neg.	0.052	
Mercury	Neg.	0.00048	Neg.	0.00048	
Beryllium	Neg.	0.00063	Neg.	0.00063	
Arsenic	Neg.	0.0029	Neg.	0.0029	
Sulfuric Acid Mist	Neg.	2.32	Neg.	6.57	
Emission Rate (TPY)					
Particulate Matter	0.31	0.00	0.55	0.13	1.00
Particulate Matter (PM10)	0.31	0.00	0.55	0.10	0.96
Sulfur Dioxide	0.062	0.00	0.110	1.82	1.99
Nitrogen Oxides	14.57	0.00	57.19	0.42	72.18
Carbon Monixide	3.64	0.00	7.37	0.03	11.04
Volatile Organic Compounds (methane)	0.31	0.00	0.06	0.00	0.37

Table 2-3. Actual Representative Emissions (1988-1990) of Regulated Pollutants, Boilers 1, 2, and 3 (Page 2 of 2)

	Boilers No. 1 & 2[a]		Boiler No. 3[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Volatile Organic Compounds (nonmethane)	0.29	0.00	0.26	0.00	0.55
Lead	Neg.	0.0000	Neg.	0.0000	0.000
Total Fluorides	Neg.	0.000	Neg.	0.000	0.000
Mercury	Neg.	0.00000	Neg.	0.00000	0.000
Beryllium	Neg.	0.00000	Neg.	0.00000	0.00000
Arsenic	Neg.	0.0000	Neg.	0.0000	0.0000
Sulfuric Acid Mist	Neg.	0.00	Neg.	0.04	0.04

Note: Calculations in this table are performed as follows: Fuel use times emission factor equals emission rate; e.g. 208.099 MM scf/yr x 3 lb/MM scf ÷ 2,000 lb/ton = 0.31 TPY (Note: Roundoff from Lotus may be slightly different than calcualtions using a calculator.).

ft^3/yr = cubic feet per year
gal/yr = gallons per year
% = percent
lb/mm = pounds per millimeter
scf = standard cubic feet
gal = gallons
Btu/hr = British thermal unit per hour
PM = particulate matte
PM10 = particulate matter (PM10)
TPY = tons per year

[a] Boilers 1 and 2 have heat input capacities less than 100 x 10^6 British thermal units per hour; therefore, emission factors for industrial boilers were used.
[b] Boiler 3 has a heat input capacity of greater than 100 x 10^6 British thermal units per hour; therefore, emission factors for utility boilers were used.
[c] Based on annual operating reports (see Appendix B).
[d] Based on equation: 10 S + 3, where S = sulfur content. PM10 is 71% of PM emissions.
[e] Based on equation: 157 S, where S = sulfur content.
[f] Adjusted based on hours of operation and fuel usage; AP-42 load chart used (see FDER letter of 12/31/91).

Table 2-4. Actual Representative Emissions of Regulated Pollutants, Boilers 4 and 5 (Page 1 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Natural Gas Burned					
(MM ft^3/yr)	155.542		452.609		
No. 6 Fuel Oil					
(gal/yr)		55,207		190,515	
(% sulfur)		1.623		1.97	
<u>Emission Factor</u>	lb/MM scf	lb/1,000 gal	lb/MM scf	lb/1,000 gal	
Particulate Matter	3	19.23[d]	3	22.7[d]	
Particulate Matter (PM10)	3	13.65[d]	3	16.12[d]	
Sulfur Dioxide	0.6	254.8[e]	0.6	309.3[e]	
Nitrogen Oxides	140	55	281.2[f]	67	
Carbon Monoxide	35	5	40	5	
Volatile Organic Compounds (methane)	3	1	0.3	0.28	
Volatile Organic Compounds (nonmethane)	2.8	0.28	1.4	0.76	
Lead	Neg.	0.0042	Neg.	0.0042	
Fluorides	Neg.	0.052	Neg.	0.052	
Mercury	Neg.	0.00048	Neg.	0.00048	
Beryllium	Neg.	0.00063	Neg.	0.00063	
Arsenic	Neg.	0.0029	Neg.	0.0029	
Sulfuric Acid Mist	Neg.	3.98	Neg.	7.0	
<u>Emission Rate (TPY)</u>					
Particulate Matter	0.23	0.53	0.68	2.16	3.61
Particulate Matter (PM10)	0.23	0.38	0.68	1.54	2.82
Sulfur Dioxide	0.05	7.03	0.14	29.46	36.68
Nitrogen Oxides	10.89	1.52	63.64	6.38	82.43
Carbon Monoxide	2.72	0.14	9.05	0.48	12.39
Volatile Organic Compounds (methane)	0.23	0.03	0.07	0.03	0.36

Table 2-4. Actual Representative Emissions of Regulated Pollutants, Boilers 4 and 5 (Page 2 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Volatile Organic Compounds (nonmethane)	0.22	0.01	0.32	0.07	0.61
Lead	Neg.	0.0001	Neg.	0.0004	0.0005
Fluorides	Neg.	0.0014	Neg.	0.0050	0.006
Mercury	Neg.	0.00001	Neg.	0.00005	0.00006
Beryllium	Neg.	0.00002	Neg.	0.00006	0.00008
Arsenic	Neg.	0.0001	Neg.	0.0003	0.0004
Sulfuric Acid Mist	Neg.	0.11	Neg.	0.67	0.78

Note: Calculations in this table are performed as follows: Fuel use times emission factor equals emission rate; e.g. 155.542 MM scf/yr x 3 lb/MM scf ÷ 2,000 lb/ton = 0.23 TPY (Note: Roundoff from Lotus may be slightly different than calculations using a calculator.).

ft^3/yr = cubic feet per year
gal/yr = gallons per year
% = percent
lb/mm = pounds per millimeter
scf = standard cubic feet
gal = gallons
Btu/hr = British thermal unit per hour
PM = particulate matter
PM10 = particulate matter (PM10)
TPY = tons per year

[a] Boiler 4 has heat input capacity of less than 100 x 10^6 Btu/hr; therefore, emissions factors for industrial boilers were used.
[b] Boiler 5 has a heat input capacity of greater than 100 x 10^6 Btu/hr; therefore, emission factors for utility boilers were used.
[c] Based on annual operating reports (see Appendix B).
[d] Based on equation: 10 S + 3, where S = sulfur content. PM10 is 71% of PM emissions.
[e] Based on equation: 157 S, where S = sulfur content.
[f] Based on hours of operation and fuel use. Used AP-42 load correction figure (see FDER letter dated 12/31/91).

Table 2-5. Emissions of Regulated Pollutants for Boilers 4 & 5 After Commercial Operation of Cogeneration Plant (Page 1 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 2 Fuel Oil	Natural Gas	No. 2 Fuel Oil	Total
Natural Gas Burned[c]					
(MM ft^3/yr)	20		125		
No. 2 Fuel Oil[c]					
(gal/yr)		15,000		50,000	
(% sulfur)		0.5		0.5	
Emission Factor	lb/MM scf	lb/1,000 gal	lb/MM scf	lb/1,000 gal	
Particulate Matter	3	8[d]	3	8[d]	
Particulate Matter (PM10)	3	5.68[d]	3	5.68[d]	
Sulfur Dioxide	0.6	78.5[e]	0.6	78.5[e]	
Nitrogen Oxides	140	20	281.2	24	
Carbon Monoxide	35	5	40	5	
Volatile Organic Compounds (methane)	3	0.052	0.3	0.052	
Volatile Organic Compounds (nonmethane)	2.8	0.2	1.4	0.2	
Lead	Neg.	0.0013	Neg.	0.0042	
Fluorides	Neg.	0.0049	Neg.	0.052	
Mercury	Neg.	0.00045	Neg.	0.00048	
Beryllium	Neg.	0.00038	Neg.	0.00063	
Arsenic	Neg.	0.00063	Neg.	0.0029	
Sulfuric Acid Mist	Neg.	1.225	Neg.	1.225	
Emission Rate (TPY)					
Particulate Matter	0.03	0.06	0.19	0.20	0.48
Particulate Matter (PM10)	0.03	0.04	0.19	0.14	0.40
Sulfur Dioxide	0.01	0.59	0.04	1.96	2.59
Nitrogen Oxides	1.40	0.15	17.58	0.61[f]	19.73
Carbon Monoxide	0.35	0.04	2.50	0.13	3.01
Volatile Organic Compounds (methane)	0.03	0.00	0.02	0.00	0.05
Volatile Organic Compounds (nonmethane)	0.03	0.00	0.09	0.01	0.12

Table 2-5. Emissions of Regulated Pollutants for Boilers 4 & 5 After Commercial Operation of Cogeneration Plant (Page 2 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 2 Fuel Oil	Natural Gas	No. 2 Fuel Oil	Total
Lead	Neg.	0.00001	Neg.	0.00011	0.0001
Fluorides	Neg.	0.00004	Neg.	0.00130	0.001
Mercury	Neg.	0.00000	0.0000	0.00001	0.00000
Beryllium	Neg.	0.00000	Neg.	0.00002	0.00002
Arsenic	Neg.	0.00000	Neg.	0.00007	0.0001
Sulfuric Acid Mist	Neg.	0.01	Neg.	0.03	0.04

Note: Calculations in this table are performed as follows: Fuel use times emission factor equals emission rate; e.g. 20 MM scf/yr x 3 lb/MM scf ÷ 2,000 lb/ton = 0.03 TPY (Note: Roundoff from Lotus may slightly different than calculations using a calculator.).

ft^3/yr = cubic feet per year
gal/yr = gallons per year
% = percent
lb/mm = pounds per millimeter
scf = standard cubic feet
gal = gallons
Btu/hr = British thermal unit per hour
PM = particulate matter
PM10 = particulate matter (PM10)
TPY = tons per year

[a] Boiler 4 has a heat input capacity of less than 100 x 10^6 Btu/hr; therefore, emissions factors for industrial boilers were used.
[b] Boiler 5 has a heat input capacity of greater than 100 x 10^6 Btu/hr; therefore, emission factors for utility boilers were used.
[c] Based on annual operating reports (See Appendix A).
[d] Based on equation: 10 S + 3, where S = sulfur content. PM10 is 71% of PM emissions.
[e] Based on equation: 157 S, where S = sulfur content.
[f] Nitrogen oxides emissions based on ratio of residual and distillate oil emission factors [67 lb/10^3 gallons x 20 lb/10^3 gallons (for distillate) ÷ 55 lb/10^3 gallons (for residual)].

Table 2-6. Net Emission Reductions From Boilers 1 Through 5 at UF Central Heating Plant

Pollutant	Net Emission Reduction (TPY) Boilers[a] 1, 2 and 3	Boilers[b] 4 and 5	Total
Particulate Matter	-1.00	-3.13	-4.13
Particulate Matter (PM10)	-0.96	-2.42	-3.38
Sulfur Dioxide	-1.99	-34.08	-36.07
Nitrogen Oxides	-72.18	-62.69	-134.87
Carbon Monoxide	-11.04	-9.38	-20.41
Volatile Organic Compounds (methane)	-0.37	-0.31	-0.67
Volatile Organic Compounds (nonmethane)	-0.55	-0.49	-1.05
Lead	-0.0000	-0.0004	-0.0004
Fluorides	-0.0003	-0.0051	-0.0054
Mercury	-0.00000	-0.00	-0.00
Beryllium	-0.00000	-0.00006	-0.00006
Arsenic	-0.0000	-0.0003	-0.0003
Sulfuric Acid Mist	-0.0411	-0.7366	-0.7777

Note: TPY = tons per year.

[a]Based on emissions in Table 2-3.
[b]Based on subtracting emissions in Table 2-4 from emissions in Table 2-5.

3.4.2 PSD REVIEW

3.4.2.1 Pollutant Applicability

The proposed project is considered to be a modification to a major facility because the facility is listed as one of the "List of 28" and potential emissions of any regulated pollutant exceed 100 TPY; therefore, PSD review is required for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 3-2 (i.e., major modification). As shown, potential emissions from the proposed project will exceed the PSD significant emission rate for CO. Therefore, the project is subject to PSD review for this pollutant.

Table 3-3. Net Increase in Emissions Due To the UF Cogeneration Facility Compared to the PSD Significant Emission Rates

Pollutant	Emissions (TPY) Potential Emissions From Proposed Project	Net Emission Reduction From Boilers 1-5	Net Emissions Increase	Significant Emission Rate	PSD Review
Sulfur Dioxide	26.6	36.1	-9.5	40	No
Particulate Matter (TSP)	13.8	4.1	9.7	25	No
Particulate Matter (PM10)	13.8	3.4	10.4	15	No
Nitrogen Dioxide	174.6	134.9	39.7	40	No
Carbon Monoxide	326.7	20.4	306.3	100	Yes
Volatile Organic Compounds	17.5	1.05	16.5	40	No
Lead	0.00034	0.0004	0.0002	0.6	No
Sulfuric Acid Mist	2.4	0.78	1.6	7	No
Total Fluorides	0.0014	0.0054	-0.004	3	No
Total Reduced Sulfur[a]	Neg	Neg	Neg	10	No
Reduced Sulfur Compounds[a]	Neg	Neg	Neg	10	No
Hydrogen Sulfide[a]	Neg	Neg	Neg	10	No
Asbestos[a]	Neg	Neg	Neg	0.007	No
Beryllium	0.00011	0.00006	0.00004	0.0004	No
Mercury	0.00013	Neg	0.00013	0.1	No
Vinyl Chloride[a]	Neg	Neg	Neg	1	No
Benzene[a]	Neg	Neg	Neg	0	No
Radionuclides[a]	Neg	Neg	Neg	0	No
Inorganic Arsenic	0.00018	0.0003	-0.00012	0	No

Note: Neg = Negligible.
TPY = tons per year.
All calculations based on 59°F peak load condition.

[a]Emissions of these pollutants considered not to have any emission rate increase.

APPENDIX A

Table A-1. Design Information and Stack Parameters for University of Florida Cogeneration Project

Data A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine Fuel Oil D
General:			
Power (kW)	43,262.0	NA	43,098.0
Heat Rate (Btu/kwh)	8,043.0	NA	8,877.0
Heat Input (mmBtu/hr)	348.0	187.0	382.6
Fuel Oil (lb/hr)	18,313.5	9,842.1	20,792.4
(cf/hr)	367,818.5	197,674.4	
Fuel:			
Heat Content - (LHV)	19,000 Btu/lb	19,000 Btu/lb	18,400 Btu/lb
Sulfur	1 gr/100cf	1 gr/100cf	0.5
CT Exhaust:			
Volume Flow (acfm)	564,678		569,684
Volume Flow (scfm)	239,478		235,916
Mass Flow (lb/hr)	1,036,522		1,030,290
Temperature (oF)	785		815
Moisture (% Vol.)	11.25		8.54
Oxygen (% Vol.)	13.73		13.60
Molecular Weight	27.80		28.05
Steam Injected (lb/hr)	31,402		22,504
HRSG Stack:			
Volume Flow (acfm)	325,200		320,364
Temperature (oF)	257		257
Diameter (ft)	10		9.8
Velocity (ft/sec)	72.59		71.51

Source: General Electric and Stewart and Stevenson, 1991.
Note: All data shown on this table and subsequent tables are for the combustion turbine and duct burner.

Table A-2. Maximum Criteria Pollutant Emissions for Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine Fuel Oil D
Particulate:			
Basis	Manufacturer	0.01 lb/mmBtu	Manufacturer
lb/hr	2.50	1.87	10.0
TPY	10.95	2.46	1.1
Sulfur Dioxide:			
Basis	1 gr/100 cf	1 gr/100 cf	0.5 % Sulfur
lb/hr	1.05	0.56	197.53
TPY	4.60	0.74	21.6
Nitrogen Oxides:			
Basis	25 ppm*	0.1 lb/mmBtu	42 ppm*
lb/hr	35.0	18.7	66.3
TPY	153.4	24.57	7.3
ppm	25.0	NA	42.0
Carbon Monoxide:			
Basis	75 ppm+	0.15 lb/mmBtu	75 ppm+
lb/hr	69.5	28.1	70.5
TPY	304.37	36.86	7.7
ppm	75.0	NA	75.0
VOC's:			
Basis	4 ppm+	0.043 lb/mmBtu	10 ppm+
lb/hr	1.59	8.04	4.03
TPY	7.0	10.57	0.4
ppm	4.0	NA	10.0
Lead:			
Basis			EPA(1988)
lb/hr	NA	NA	3.40E-03
TPY	NA	NA	3.73E-04

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions
Note: Annual emission for CT when firning natural gas based on 8,760 hrs/yr and 219 hrs/yr for fuel oil firing. Annual emissions for duct burners on 2,628 hrs/yr (30% capacity factor).

Table A-3. Maximum Other Regulated Pollutant Emissions for UF Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine No.2 Oil D
As (lb/hr)	NEG.	NEG.	0.0016068399732
(TPY)	NEG.	NEG.	1.76E-04
Be (lb/hr)	NEG.	NEG.	0.000956452365
(TPY)	NEG.	NEG.	1.05E-04
Hg (lb/hr)	NEG.	NEG.	1.15E-03
(TPY)	NEG.	NEG.	1.26E-04
F (lb/hr)	NEG.	NEG.	0.012433880745
(TPY)	NEG.	NEG.	1.36E-03
H2SO4 (lb/hr)	8.04E-02	4.32E-02	1.51E+01
(TPY)	3.52E-01	0.06	1.65E+00

Sources: EPA, 1988; EPA, 1980

Table A-4. Maximum Non-Regulated Pollutant Emissions for UF Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine No.2 Oil D
Manganese (lb/hr)	NEG.	NEG.	2.46E-03
(TPY)	NEG.	NEG.	2.70E-04
Nickel (lb/hr)	NEG.	NEG.	6.50E-02
(TPY)	NEG.	NEG.	7.12E-03
Cadmium (lb/hr)	NEG.	NEG.	4.02E-03
(TPY)	NEG.	NEG.	4.40E-04
Chromium (lb/hr)	NEG.	NEG.	1.82E-02
(TPY)	NEG.	NEG.	1.99E-03
Copper (lb/hr)	NEG.	NEG.	1.07E-01
(TPY)	NEG.	NEG.	1.17E-02
Vanadium (lb/hr)	NEG.	NEG.	2.67E-02
(TPY)	NEG.	NEG.	2.92E-03
Selenium (lb/hr)	NEG.	NEG.	8.98E-03
(TPY)	NEG.	NEG.	9.83E-04
POM (lb/hr)	3.88E-04	2.09E-04	1.07E-04
(TPY)	1.70E-03	2.74E-04	1.17E-05
Formaldehyde (lb/hr)	3.07E-02	7.57E-02	1.55E-01
(TPY)	1.35E-01	9.95E-02	1.70E-02

Source: EPA, 1988.

Table A-5. Maximum Emissions for Additional Non-Regulated Pollutant for UF Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine No.2 Oil D
Antimony (lb/hr)	NEG.	NEG.	8.36E-03
(TPY)	NEG.	NEG.	9.15E-04
Barium (lb/hr)	NEG.	NEG.	7.47E-03
(TPY)	NEG.	NEG.	8.18E-04
Colbalt (lb/hr)	NEG.	NEG.	3.47E-03
(TPY)	NEG.	NEG.	3.80E-04
Zinc (lb/hr)	NEG.	NEG.	2.61E-01
(TPY)	NEG.	NEG.	2.86E-02
Chlorine^a (lb/hr)	NEG.	NEG.	1.04E-02
(TPY)	NEG.	NEG.	1.14E-03

Source: EPA, 1979
^a Assumes 0.5 ppm in fuel oil.

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A:A1: [W24] 'Table A-1.  Design Information and Stack Parameters for University of Florida (UF)
A:E1: [W6] 1
A:A2: [W24] '          Cogeneration Project
A:E2: [W6] (E1+1)
A:A3: [W24] \_
A:B3: [W18] \_
A:C3: [W18] \_
A:D3: [W18] \_
A:E3: [W6] (E2+1)
A:E4: [W6] (E3+1)
A:A5: [W24] ^Data
A:B5: [W18] "Gas Turbine
A:C5: [W18] "Duct Burner
A:D5: [W18] "Gas Turbine
A:E5: [W6] (E4+1)
A:B6: [W18] "Natural Gas
A:C6: [W18] "Natural Gas
A:D6: [W18] "Fuel Oil
A:E6: [W6] (E5+1)
A:A7: [W24] ^A
A:B7: [W18] "B
A:C7: [W18] "C
A:D7: [W18] "D
A:E7: [W6] (E6+1)
A:A8: [W24] \_
A:B8: [W18] \_
A:C8: [W18] \_
A:D8: [W18] \_
A:E8: [W6] (E7+1)
A:E9: [W6] (E8+1)
A:A10: [W24] ^General:
A:E10: [W6] (E9+1)
A:A11: [W24] 'Power (kW)
A:B11: (,1) [W18] 43262 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  From GE
A:C11: (,1) [W18] "NA
A:D11: (,1) [W18] 43098 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  From GE
A:E11: [W6] (E10+1)
A:A12: [W24] 'Heat Rate (Btu/kwh)
A:B12: (,1) [W18] 8043  . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  From GE
A:C12: (,1) [W18] "NA
A:D12: (,1) [W18] 8877  . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  From GE
A:E12: [W6] (E11+1)
A:A13: [W24] 'Heat Input (mmBtu/hr)
A:B13: (,1) [W18] (B11*B12/1000000) . . . . . . . . . . . . . . . . . . . . . . . . .  Power * Heat Rate
A:C13: (,1) [W18] 187 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . .  Maximum Proposed
A:D13: (,1) [W18] (D11*D12/1000000) . . . . . . . . . . . . . . . . . . . . . . . . .  Power * Heat Rate
A:E13: [W6] (E12+1)
A:A14: [W24] 'Fuel Oil (lb/hr)
A:B14: (,1) [W18] (B13/0.019) . . . . . . . . . . . . . . . . . . . . . . . .  Heat Input ÷ Heat Content
A:C14: (,1) [W18] (C13/0.019)
A:D14: (,1) [W18] (D13/0.0184)
A:E14: [W6] (E13+1)
A:A15: [W24] '        (cf/hr)
A:B15: (,1) [W18] (B13/946*10^6)  . . . . . . . . . . . . . . . . . . . . . .  Heat Input ÷ Heat Content
A:C15: (,1) [W18] (C13/946*10^6)
A:E15: [W6] (E14+1)
A:E16: [W6] (E15+1)
A:A17: [W24] ^Fuel:
A:E17: [W6] (E16+1)
A:A18: [W24] 'Heat Content - (LHV)
A:B18: (,1) [W18] "19,000 Btu/lb  . . . . . . . . . . . . . . . . . . . . . . . . .  Fuel Specification
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A:C18: (,1) [W18] "19,000 Btu/lb
A:D18: (,1) [W18] "18,400 Btu/lb
A:E18: [W6] (E17+1)
A:A19: [W24] 'Sulfur
A:B19: (,1) [W18] "1 gr/100cf . . . . . . . . . . . . . . . . . . . . . . . . . Maximum Sulfur Content in Natural Gas
A:C19: (,1) [W18] "1 gr/100cf
A:D19: (,1) [W18] 0.5 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Maximum Sulfur Content in Fuel Oil
A:E19: [W6] (E18+1)
A:E20: [W6] (E19+1)
A:A21: [W24] ^CT Exhaust:
A:E21: [W6] (E20+1)
A:A22: [W24] 'Volume Flow (acfm)
A:B22: (,0) [W18] (B24*1545*(460+B25)/(B28*2116.8*60)) . . . . . . . . . . . . . . . . . . . . . . . . See Note A
A:D22: (,0) [W18] (D24*1545*(460+D25)/(D28*2116.8*60))
A:E22: [W6] (E21+1)
A:A23: [W24] 'Volume Flow (scfm)
A:B23: (,0) [W18] (B24*1545*(460+68)/(B28*2116.8*60)) . . . . . . . . . . . . . . . . . . . . . . . . . See Note A
A:D23: (,0) [W18] (D24*1545*(460+68)/(D28*2116.8*60))
A:E23: [W6] (E22+1)
A:A24: [W24] 'Mass Flow (lb/hr)
A:B24: (,0) [W18] 1036522 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:D24: (,0) [W18] 1030290
A:E24: [W6] (E23+1)
A:A25: [W24] 'Temperature (oF)
A:B25: (,0) [W18] 785 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:D25: (,0) [W18] 815
A:E25: [W6] (E24+1)
A:A26: [W24] 'Moisture (% Vol.)
A:B26: (F2) [W18] 11.25 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:D26: (F2) [W18] 8.54
A:E26: [W6] (E25+1)
A:A27: [W24] 'Oxygen (% Vol.)
A:B27: (F2) [W18] 13.73 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:D27: (F2) [W18] 13.6
A:E27: [W6] (E26+1)
A:A28: [W24] 'Molecular Weight
A:B28: (F2) [W18] 27.8  . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Calculated from GE
A:D28: (F2) [W18] 28.05
A:E28: [W6] (E27+1)
A:A29: [W24] 'Steam Injected (lb/hr)
A:B29: (,0) [W18] 31402 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:D29: (,0) [W18] 22504
A:E29: [W6] (E28+1)
A:E30: [W6] (E29+1)
A:A31: [W24] ^HRSG Stack:
A:E31: [W6] (E30+1)
A:A32: [W24] 'Volume Flow (acfm)
A:B32: (,0) [W18] (B22*(B33+460)/(B25+460)) . . . . . . . . . . . . . . . . . . . . . . Adjustment for Temperature
A:D32: (,0) [W18] (D22*(D33+460)/(D25+460))
A:E32: [W6] (E31+1)
A:A33: [W24] 'Temperature (oF)
A:B33: (,0) [W18] 257 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From Design Engineer
A:D33: (,0) [W18] 257
A:E33: [W6] (E32+1)
A:A34: [W24] 'Diameter (ft)
A:B34: (F0) [W18] 9.75
A:D34: (,1) [W18] 9.75
A:E34: [W6] (E33+1)
A:A35: [W24] 'Velocity (ft/sec)
A:B35: (F2) [W18] (B32/60/(B34^2*3.14159/4))  . . . . . . . . . . . . . . . . . . . . . . . . . Volume ÷ Flow
A:D35: (F2) [W18] (D32/60/(D34^2*3.14159/4))
A:E35: [W6] (E34+1)
```

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A:E36: [W6] (E35+1)
A:A37: [W24] \_
A:B37: [W18] \_
A:C37: [W18] \_
A:D37: [W18] \_
A:E37: [W6] (E36+1)
A:E38: [W6] (E37+1)
A:A39: [W24] 'Source: General Electric and Stewart and Stevenson, 1991.
A:E39: [W6] (E38+1)
A:A40: [W24] 'Note: All data shown on this table and subsequent tables are for each
A:E40: [W6] (E39+1)
A:A41: [W24] '      combustion turbine and duct burner.
A:E41: [W6] (E40+1)
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A:A47: [W24] 'Table A-2.  Maximum Criteria Pollutant Emissions for
A:E47: [W6] 47
A:A48: [W24] '           Cogeneration Project
A:E48: [W6] (E47+1)
A:A49: [W24] \_
A:B49: [W18] \_
A:C49: [W18] \_
A:D49: [W18] \_
A:E49: [W6] (E48+1)
A:E50: [W6] (E49+1)
A:A51: [W24] ^Pollutant
A:B51: [W18] "Gas Turbine
A:C51: [W18] "Duct Burner
A:D51: [W18] "Gas Turbine
A:E51: [W6] (E50+1)
A:B52: [W18] "Natural Gas
A:C52: [W18] "Natural Gas
A:D52: [W18] "Fuel Oil
A:E52: [W6] (E51+1)
A:A53: [W24] ^A
A:B53: [W18] "B
A:C53: [W18] "C
A:D53: [W18] "D
A:E53: [W6] (E52+1)
A:A54: [W24] \_
A:B54: [W18] \_
A:C54: [W18] \_
A:D54: [W18] \_
A:E54: [W6] (E53+1)
A:E55: [W6] (E54+1)
A:A56: [W24] 'Particulate:
A:E56: [W6] (E55+1)
A:A57: [W24] '  Basis
A:B57: (,1) [W18] "Manufacturer
A:C57: (,1) [W18] "0.01 lb/mmBtu
A:D57: (,1) [W18] "Manufacturer
A:E57: [W6] (E56+1)
A:A58: [W24] '  lb/hr
A:B58: (F2) [W18] 2.5 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:C58: (F2) [W18] (C13*0.01)  . . . . . . . . . . . . . . . . . . . . . . . .  Emission Factor Based on GE
A:D58: (F1) [W18] 10  . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:E58: [W6] (E57+1)
A:A59: [W24] '  TPY
A:B59: (F2) [W18] (B58*8760/2000) . . . . . . . . . . . . . . . . . . . .  Emissions * 8,760 hours/year ÷ 2,000 lb/ton
A:C59: (F2) [W18] (C58*4.38*0.3)  . . . . . . . . . . . . . . . . . . . Emissions * 4.38 TPY/lb/hr ÷ 0.3 Capacity Factor
A:D59: (,1) [W18] (D58*219/2000)  . . . . . . . . . . . . . . . . . . . .  Emissions * 219 hours/year ÷ 2,000 lb/ton
A:E59: [W6] (E58+1)
A:E60: [W6] (E59+1)
A:A61: [W24] 'Sulfur Dioxide:
A:E61: [W6] (E60+1)
A:A62: [W24] '  Basis
A:B62: (,1) [W18] "1 gr/100 cf
A:C62: (,1) [W18] "1 gr/100 cf
A:D62: (,1) [W18] "0.5 % Sulfur
A:E62: [W6] (E61+1)
A:A63: [W24] '  lb/hr
A:B63: (F2) [W18] (B15*1/7000*2/100)  . . . . . . . . .  Fuel Used (CF/HR) * Sulfur Content * 2 lb SO2/lb S * 1/100 CF
A:C63: (F2) [W18] (C15*1/7000*2/100)
A:D63: (F2) [W18] (D14*0.005*2*0.95)  . . . . . . . .  Fuel Used (lb/hr) * Sulfur Content * 2 lb SO2/lb S * 95% Emitted
A:E63: [W6] (E62+1)
A:A64: [W24] '  TPY
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A:B64: (F2) [W18] (B63*8760/2000)
A:C64: (F2) [W18] (C63*4.38*0.3)
A:D64: (,1) [W18] (D63*219/2000)
A:E64: [W6] (E63+1)
A:E65: [W6] (E64+1)
A:A66: [W24] 'Nitrogen Oxides:
A:E66: [W6] (E65+1)
A:A67: [W24] '  Basis
A:B67: (,1) [W18] "25 ppm*
A:C67: (,1) [W18] "0.1 lb/mmBtu
A:D67: (,1) [W18] "42 ppm*
A:E67: [W6] (E66+1)
A:A68: [W24] '  lb/hr
A:B68: (,1) [W18] (B70/5.9*(20.9*(1-B26/100)-B27)*B22*2116.8*46*60/(1545*(460+B25)*1000000)) . . . . . . . See Note B
A:C68: (,1) [W18] (C13*0.1) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Heat Input * Emission Factor
A:D68: (,1) [W18] (D70/5.9*(20.9*(1-D26/100)-D27)*D22*2116.8*46*60/(1545*(460+D25)*1000000)) . . . . . . . See Note B
A:E68: [W6] (E67+1)
A:A69: [W24] '  TPY
A:B69: (F1) [W18] (B68*8760/2000)
A:C69: (F2) [W18] (C68*4.38*0.3)
A:D69: (,1) [W18] (D68*219/2000)
A:E69: [W6] (E68+1)
A:A70: [W24] '  ppm
A:B70: (,1) [W18] 25 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:C70: (,1) [W18] "NA
A:D70: (,1) [W18] 42 . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:E70: [W6] (E69+1)
A:E71: [W6] (E70+1)
A:A72: [W24] 'Carbon Monoxide:
A:E72: [W6] (E71+1)
A:A73: [W24] '  Basis
A:B73: (,1) [W18] "75 ppm+ . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:C73: (,1) [W18] "0.15 lb/mmBtu . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From Engineer
A:D73: (,1) [W18] "75 ppm+ . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . From GE
A:E73: [W6] (E72+1)
A:A74: [W24] '  lb/hr
A:B74: (,1) [W18] (B76*(1-B26/100)*B22*2116.8*28*60/(1545*(460+B25)*1000000)) . . . . . . . . . . . . . . . See Note C
A:C74: (,1) [W18] (C13*0.15) . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . . Heat Input * Emission Factor
A:D74: (,1) [W18] (D76*(1-D26/100)*D22*2116.8*28*60/(1545*(460+D25)*1000000)) . . . . . . . . . . . . . . . See Note C
A:E74: [W6] (E73+1)
A:A75: [W24] '  TPY
A:B75: (F2) [W18] (B74*8760/2000)
A:C75: (F2) [W18] (C74*4.38*0.3)
A:D75: (,1) [W18] (D74*219/2000)
A:E75: [W6] (E74+1)
A:A76: [W24] '  ppm
A:B76: (,1) [W18] 75
A:C76: (,1) [W18] "NA
A:D76: (,1) [W18] 75
A:E76: [W6] (E75+1)
A:E77: [W6] (E76+1)
A:A78: [W24] 'VOC's:
A:E78: [W6] (E77+1)
A:A79: [W24] '  Basis
A:B79: (,1) [W18] "4 ppm+
A:C79: (,1) [W18] "0.043 lb/mmBtu
A:D79: (,1) [W18] "10 ppm+
A:E79: [W6] (E78+1)
A:A80: [W24] '  lb/hr
A:B80: (F2) [W18] (B82*(1-B26/100)*B22*2116.8*12*60/(1545*(460+B25)*1000000)) . . . . . . . . . . . . . . See Note C
A:C80: (F2) [W18] (C13*0.043)
A:D80: (F2) [W18] (D82*(1-D26/100)*D22*2116.8*12*60/(1545*(460+D25)*1000000)) . . . . . . . . . . . . . . See Note C
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A:E80: [W6] (E79+1)
A:A81: [W24] '  TPY
A:B81: (,1) [W18] (B80*8760/2000)
A:C81: (F2) [W18] (C80*4.38*0.3)
A:D81: (,1) [W18] (D80*219/2000)
A:E81: [W6] (E80+1)
A:A82: [W24] '  ppm
A:B82: (,1) [W18] 4
A:C82: (,1) [W18] "NA
A:D82: (,1) [W18] 10
A:E82: [W6] (E81+1)
A:E83: [W6] (E82+1)
A:A84: [W24] 'Lead:
A:E84: [W6] (E83+1)
A:A85: [W24] '  Basis
A:D85: [W18] "EPA(1988)
A:E85: [W6] (E84+1)
A:A86: [W24] '  lb/hr
A:B86: (S2) [W18] "NA
A:C86: (S2) [W18] "NA
A:D86: (S2) [W18] (D13*8.9/1000000) . . . . . . . . . . . . .  From EPA 1988; Page 4-156; Heat Input * Emission Factor
A:E86: [W6] (E85+1)
A:A87: [W24] '  TPY
A:B87: (S2) [W18] "NA
A:C87: (S2) [W18] "NA
A:D87: (S2) [W18] (D86*219/2000)
A:E87: [W6] (E86+1)
A:A88: [W24] \_
A:B88: [W18] \_
A:C88: [W18] \_
A:D88: [W18] \_
A:E88: [W6] (E87+1)
A:E89: [W6] (E88+1)
A:A90: [W24] '* corrected to 15% O2 dry conditions
A:E90: [W6] (E89+1)
A:A91: [W24] '+ corrected to dry conditions
A:E91: [W6] (E90+1)
A:A92: [W24] 'Note: Annual emission for CT when firning natural gas based on 8,760 hrs/yr
A:E92: [W6] (E91+1)
A:A93: [W24] '      and 219 hrs/yr for fuel oil firing.  Annual emissions for duct burners
A:E93: [W6] (E92+1)
A:A94: [W24] '      on 2,628 hrs/yr (30% capacity factor).
A:E94: [W6] (E93+1)
```

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A:A96: [W24] 'Table A-3.  Maximum Other Regulated Pollutant Emissions for UF
A:E96: [W6] 96
A:A97: [W24] '          Cogeneration Project
A:E97: [W6] (E96+1)
A:A98: [W24] \_
A:B98: [W18] \_
A:C98: [W18] \_
A:D98: [W18] \_
A:E98: [W6] (E97+1)
A:E99: [W6] (E98+1)
A:A100: [W24] ^Pollutant
A:B100: [W18] "Gas Turbine
A:C100: [W18] "Duct Burner
A:D100: [W18] "Gas Turbine
A:E100: [W6] (E99+1)
A:B101: [W18] "Natural Gas
A:C101: [W18] "Natural Gas
A:D101: [W18] "No.2 Oil
A:E101: [W6] (E100+1)
A:A102: [W24] ^A
A:B102: [W18] "B
A:C102: [W18] "C
A:D102: [W18] "D
A:E102: [W6] (E101+1)
A:A103: [W24] \_
A:B103: [W18] \_
A:C103: [W18] \_
A:D103: [W18] \_
A:E103: [W6] (E102+1)
A:E104: [W6] (E103+1)
A:A105: [W24] '  As (lb/hr)
A:B105: [W18] "NEG.
A:C105: [W18] "NEG.
A:D105: [W18] (D13*4.2/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E105: [W6] (E104+1)
A:A106: [W24] '     (TPY)
A:B106: [W18] "NEG.
A:C106: [W18] "NEG.
A:D106: (S2) [W18] (D105*219/2000)
A:E106: [W6] (E105+1)
A:E107: [W6] (E106+1)
A:A108: [W24] '  Be (lb/hr)
A:B108: [W18] "NEG.
A:C108: [W18] "NEG.
A:D108: [W18] (D13*2.5/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E108: [W6] (E107+1)
A:A109: [W24] '     (TPY)
A:B109: [W18] "NEG.
A:C109: [W18] "NEG.
A:D109: (S2) [W18] (D108*219/2000)
A:E109: [W6] (E108+1)
A:E110: [W6] (E109+1)
A:A111: [W24] '  Hg (lb/hr)
A:B111: [W18] "NEG.
A:C111: [W18] "NEG.
A:D111: (S2) [W18] (D13*3/1000000)  . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E111: [W6] (E110+1)
A:A112: [W24] '     (TPY)
A:B112: [W18] "NEG.
A:C112: [W18] "NEG.
A:D112: (S2) [W18] (D111*219/2000)
A:E112: [W6] (E111+1)
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A:E113: [W6] (E112+1)
A:A114: [W24] ' F (lb/hr)
A:B114: [W18] "NEG.
A:C114: [W18] "NEG.
A:D114: [W18] (D13*32.5/1000000) . . . . From EPA 1981; Table 6-1, 2.324 pq/J * 14 pq/J = 32.5 lb/10^6 BTU
A:E114: [W6] (E113+1)
A:A115: [W24] ' (TPY)
A:B115: [W18] "NEG.
A:C115: [W18] "NEG.
A:D115: (S2) [W18] (D114*219/2000)
A:E115: [W6] (E114+1)
A:E116: [W6] (E115+1)
A:A117: [W24] ' H2SO4 (lb/hr)
A:B117: (S2) [W18] (B63*0.05*3.06/2) . . . . SO_2 Emission * 0.005 (%H_2SO_4 Formed) * MW_{H2SO4}/MW_{SO2}
A:C117: (S2) [W18] (C63*0.05*3.06/2) . . . . SO_2 emissions * %H_2SO_4 formed (5%) * MW_{H2SO4}/MW_{SO2} * correction to total SO_2
A:D117: (S2) [W18] (D63*0.05*3.06/2)
A:E117: [W6] (E116+1)
A:A118: [W24] ' (TPY)
A:B118: (S2) [W18] (B117*8760/2000)
A:C118: (F2) [W18] (C117*4.38*0.3)
A:D118: (S2) [W18] (D117*219/2000)
A:E118: [W6] (E117+1)
A:E119: [W6] (E118+1)
A:A120: [W24] _
A:B120: [W18] _
A:C120: [W18] _
A:D120: [W18] _
A:E120: [W6] (E119+1)
A:E121: [W6] (E120+1)
A:A122: [W24] 'Sources: EPA, 1988; EPA, 1980
A:E122: [W6] (E121+1)

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A:A125: [W24] 'Table A-4.  Maximum Non-Regulated Pollutant Emissions for UF
A:E125: [W6] 125
A:A126: [W24] '            Cogeneration Project
A:E126: [W6] (E125+1)
A:A127: [W24] \_
A:B127: [W18] \_
A:C127: [W18] \_
A:D127: [W18] \_
A:E127: [W6] (E126+1)
A:E128: [W6] (E127+1)
A:A129: [W24] ^Pollutant
A:B129: [W18] "Gas Turbine
A:C129: [W18] "Duct Burner
A:D129: [W18] "Gas Turbine
A:E129: [W6] (E128+1)
A:B130: [W18] "Natural Gas
A:C130: [W18] "Natural Gas
A:D130: [W18] "No.2 Oil
A:E130: [W6] (E129+1)
A:A131: [W24] ^A
A:B131: [W18] "B
A:C131: [W18] "C
A:D131: [W18] "D
A:E131: [W6] (E130+1)
A:A132: [W24] \_
A:B132: [W18] \_
A:C132: [W18] \_
A:D132: [W18] \_
A:E132: [W6] (E131+1)
A:E133: [W6] (E132+1)
A:A134: [W24] '  Manganese (lb/hr)
A:B134: [W18] "NEG.
A:C134: [W18] "NEG.
A:D134: (S2) [W18] (D13*6.44/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E134: [W6] (E133+1)
A:A135: [W24] '     (TPY)
A:B135: [W18] "NEG.
A:C135: [W18] "NEG.
A:D135: (S2) [W18] (D134*219/2000)
A:E135: [W6] (E134+1)
A:E136: [W6] (E135+1)
A:A137: [W24] '  Nickel (lb/hr)
A:B137: [W18] "NEG.
A:C137: [W18] "NEG.
A:D137: (S2) [W18] (D13*170/1000000)  . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E137: [W6] (E136+1)
A:A138: [W24] '     (TPY)
A:B138: [W18] "NEG.
A:C138: [W18] "NEG.
A:D138: (S2) [W18] (D137*219/2000)
A:E138: [W6] (E137+1)
A:E139: [W6] (E138+1)
A:A140: [W24] '  Cadmium (lb/hr)
A:B140: [W18] "NEG.
A:C140: [W18] "NEG.
A:D140: (S2) [W18] (D13*10.5/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E140: [W6] (E139+1)
A:A141: [W24] '     (TPY)
A:B141: [W18] "NEG.
A:C141: [W18] "NEG.
A:D141: (S2) [W18] (D140*219/2000)
A:E141: [W6] (E140+1)
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A:E142: [W6] (E141+1)
A:A143: [W24] '  Chromium (lb/hr)
A:B143: [W18] "NEG.
A:C143: [W18] "NEG.
A:D143: (S2) [W18] (D13*47.5/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E143: [W6] (E142+1)
A:A144: [W24] '    (TPY)
A:B144: [W18] "NEG.
A:C144: [W18] "NEG.
A:D144: (S2) [W18] (D143*219/2000)
A:E144: [W6] (E143+1)
A:E145: [W6] (E144+1)
A:A146: [W24] '  Copper (lb/hr)
A:B146: [W18] "NEG.
A:C146: [W18] "NEG.
A:D146: (S2) [W18] (D13*280/1000000)  . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1988, See Table 4-1
A:E146: [W6] (E145+1)
A:A147: [W24] '    (TPY)
A:B147: [W18] "NEG.
A:C147: [W18] "NEG.
A:D147: (S2) [W18] (D146*219/2000)
A:E147: [W6] (E146+1)
A:E148: [W6] (E147+1)
A:A149: [W24] '  Vanadium (lb/hr)
A:B149: [W18] "NEG.
A:C149: [W18] "NEG.
A:D149: (S2) [W18] (D13*30*2.324/1000000) . . . . . . . . . .  From EPA 1988, See Page 4-162; 2.324 pg/J = 1 lb/10^6 BTU
A:E149: [W6] (E148+1)
A:A150: [W24] '     (TPY)
A:B150: [W18] "NEG.
A:C150: [W18] "NEG.
A:D150: (S2) [W18] (D149*219/2000)
A:E150: [W6] (E149+1)
A:E151: [W6] (E150+1)
A:A152: [W24] '  Selenium (lb/hr)
A:B152: [W18] "NEG.
A:C152: [W18] "NEG.
A:D152: (S2) [W18] (D13*10.1*2.324/1000000) . . . . . . . . . . . . . . . . . . . . .  From EPA 1988, See Page 4-162
A:E152: [W6] (E151+1)
A:A153: [W24] '    (TPY)
A:B153: [W18] "NEG.
A:C153: [W18] "NEG.
A:D153: (S2) [W18] (D152*219/2000)
A:E153: [W6] (E152+1)
A:E154: [W6] (E153+1)
A:A155: [W24] '  POM (lb/hr)
A:B155: (S2) [W18] ($B$13*0.48*2.324/1000000) . . . . . . . . . . . . . . . . . . .  From EPA 1988, See Page 4-161
A:C155: (S2) [W18] ($C$13*0.48*2.324/1000000)
A:D155: (S2) [W18] ($D$13*0.12*2.324/1000000)
A:E155: [W6] (E154+1)
A:A156: [W24] '    (TPY)
A:B156: (S2) [W18] (B155*8760/2000)
A:C156: (S2) [W18] (C155*4.38*0.3)
A:D156: (S2) [W18] (D155*219/2000)
A:E156: [W6] (E155+1)
A:E157: [W6] (E156+1)
A:A158: [W24] '  Formaldehyde (lb/hr)
A:B158: (S2) [W18] ($B$13*38*2.324/1000000) . . . . . . . . . . . . . . . . . . . .  From EPA 1988, See Page 4-156
A:C158: (S2) [W18] ($C$13*405/1000000)
A:D158: (S2) [W18] ($D$13*405/1000000)
A:E158: [W6] (E157+1)
A:A159: [W24] '    (TPY)
```

```
A:B159: (S2) [W18] (B158*8760/2000)
A:C159: (S2) [W18] (C158*4.38*0.3)
A:D159: (S2) [W18] (D158*219/2000)
A:E159: [W6] (E158+1)
A:A160: [W24] \_
A:B160: [W18] \_
A:C160: [W18] \_
A:D160: [W18] \_
A:E160: [W6] (E159+1)
A:E161: [W6] (E160+1)
A:E162: [W6] (E161+1)
```

```
A:A165: [W24] 'Table A-5.  Maximum Emissions for Additional Non-Regulated Pollutant
A:E165: [W6] 165
A:A166: [W24] '            for  UF Cogeneration Project
A:E166: [W6] (E165+1)
A:A167: [W24] \_
A:B167: [W18] \_
A:C167: [W18] \_
A:D167: [W18] \_
A:E167: [W6] (E166+1)
A:E168: [W6] (E167+1)
A:A169: [W24] ^Pollutant
A:B169: [W18] "Gas Turbine
A:C169: [W18] "Duct Burner
A:D169: [W18] "Gas Turbine
A:E169: [W6] (E168+1)
A:B170: [W18] "Natural Gas
A:C170: [W18] "Natural Gas
A:D170: [W18] "No.2 Oil
A:E170: [W6] (E169+1)
A:A171: [W24] ^A
A:B171: [W18] "B
A:C171: [W18] "C
A:D171: [W18] "D
A:E171: [W6] (E170+1)
A:A172: [W24] \_
A:B172: [W18] \_
A:C172: [W18] \_
A:D172: [W18] \_
A:E172: [W6] (E171+1)
A:E173: [W6] (E172+1)
A:A174: [W24] '  Antimony (lb/hr)
A:B174: [W18] "NEG.
A:C174: [W18] "NEG.
A:D174: (S2) [W18] ($D$13*9.4*2.324/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1979, See Page 137
A:E174: [W6] (E173+1)
A:A175: [W24] '     (TPY)
A:B175: [W18] "NEG.
A:C175: [W18] "NEG.
A:D175: (S2) [W18] (D174*219/2000)
A:E175: [W6] (E174+1)
A:E176: [W6] (E175+1)
A:A177: [W24] '  Barium (lb/hr)
A:B177: [W18] "NEG.
A:C177: [W18] "NEG.
A:D177: (S2) [W18] ($D$13*8.4*2.324/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1979, See Page 137
A:E177: [W6] (E176+1)
A:A178: [W24] '     (TPY)
A:B178: [W18] "NEG.
A:C178: [W18] "NEG.
A:D178: (S2) [W18] (D177*219/2000)
A:E178: [W6] (E177+1)
A:E179: [W6] (E178+1)
A:A180: [W24] '  Colbalt (lb/hr)
A:B180: [W18] "NEG.
A:C180: [W18] "NEG.
A:D180: (S2) [W18] ($D$13*3.9*2.324/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1979, See Page 137
A:E180: [W6] (E179+1)
A:A181: [W24] '     (TPY)
A:B181: [W18] "NEG.
A:C181: [W18] "NEG.
A:D181: (S2) [W18] (D180*219/2000)
A:E181: [W6] (E180+1)
```

```
A:E182: [W6] (E181+1)
A:A183: [W24] '  Zinc (lb/hr)
A:B183: [W18] "NEG.
A:C183: [W18] "NEG.
A:D183: (S2) [W18] ($D$13*294*2.324/1000000) . . . . . . . . . . . . . . . . . . . . . . . . From EPA 1979, See Page 137
A:E183: [W6] (E182+1)
A:A184: [W24] '    (TPY)
A:B184: [W18] "NEG.
A:C184: [W18] "NEG.
A:D184: (S2) [W18] (D183*219/2000)
A:E184: [W6] (E183+1)
A:E185: [W6] (E184+1)
A:A186: [W24] '  Chlorine^a (lb/hr)
A:B186: [W18] "NEG.
A:C186: [W18] "NEG.
A:D186: (S2) [W18] (D14*0.5/1000000) . . . . . . . . . . . . . . . . . . . . . . . . . . . 0.5 ppm in Fuel Oil Assumed
A:E186: [W6] (E185+1)
A:A187: [W24] '    (TPY)
A:B187: [W18] "NEG.
A:C187: [W18] "NEG.
A:D187: (S2) [W18] (D186*219/2000)
A:E187: [W6] (E186+1)
A:A188: [W24] \_
A:B188: [W18] \_
A:C188: [W18] \_
A:D188: [W18] \_
A:E188: [W6] (E187+1)
A:E189: [W6] (E188+1)
A:A190: [W24] 'Source: EPA, 1979
A:E190: [W6] (E189+1)
A:A191: [W24] '  ^a Assumes 0.5 ppm in fuel oil.
A:E191: [W6] (E190+1)
```

EMISSION FACTORS AND CALCULATIONS

Emission factors used in the calculations were obtained from the following sources (references attached):

1. Compilation of air pollutant emiission factors (AP-42) for PM, SO_2, NO_x, CO, and VOC.

2. Estimating air toxics from coal and oil combustion sources (EPA, 1989) for As, Be, Pb, and Hg.

3. Emissions Assessment of Conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources (EPA, 1981) for F.

The conversions from $lb/10^{-12}$ Btu to $lb/10^3$ gal were calculated as follows:

Residual Oil = EF $lb/10^{12}$ Btu * 18,300 Btu/lb oil * 8.2 lb oil/gal

* 1,000/10^3 = 1.5 x 10^{-4} * EF $lb/10^3$ gal

where: EF = emission factor

Distillate Oil = EF $lb/10^{12}$ Btu * 20,996/lb oil * 7.2 lb/gal

* 1,000/10^3 = 1.512 x 10^{-4} * EF $lb/10^3$ gal

The conversion from pg/J to $lb/10^{12}$ Btu is as follows:

pg/J * 10^{-12} g/pg * lb/454 grams * 1,055 J/Btu = 2.324 $lb/10^{12}$ Btu

A

Volume is calculated based on ideal gas law:

PV = mRT/M
V = mRT/(MP) for natural gas

where: P = pressure = 2116.8 lb/ft^2
m = mass flow of gas (lb/hr)
R = universal gas constant = 1545 ft-lb/lb-mole °R
M = molecular weight of gas
T = temperature (K)

B

NO_x is calculated by correcting to 15% O_2 dry conditions using ideal gas law and moisture and O_2 conditions.

Oxygen correction:

$$V_{NOx\ (15\%)} = \frac{V_{NOx\ Dry} * 5.9}{20.9 - \%O_{2\ Dry}}$$

$$V_{NOx\ Dry} = V_{NOx\ (15\%)}\ (20.9 - \%O_{2\ Dry})\ /\ 5.9$$

$$\%O_{2\ Dry} = \%O_{2\ Act}\ /\ (1 - \%H_2O)\ ;\ \%O_{2\ Act} = \%O_{2\ Dry}\ (1 - \%H_2O)$$

$$V_{NOx\ Act} = V_{NOx\ Dry}\ (1 - \%H_2O)$$

Substituting:

$$V_{NOx\ Act} = V_{NOx\ 15\%}\ (20.9 - \%O_{2\ Dry})\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9 - (\%O_{2\ Act}\ /\ (1 - \%H_2O))]\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2)\ /\ 5.9$$

$$m_{NOx} = \frac{PVM_{NOx}}{RT} = V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2) * P * M_{NOx}\ /\ (RT * 5.9)$$

C

CO and VOC are calculated by correcting for moisture using ideal gas law. Same as NO_x calculation except only moisture correction is used:

$$V_{CO\ Act} = V_{CO\ Dry}\ (1 - \%H_2O)$$

$$m_{CO} = PV_{CO\ Act}M_{CO}\ /\ RT$$
$$= PV_{CO\ Dry}\ (1 - \%H_2O)\ M_{CO}\ /\ RT$$

pg/J = picograms per joule

SUPPLEMENT C

TO

COMPILATION OF AIR POLLUTANT EMISSION FACTORS

VOLUME I: STATIONARY POINT AND AREA SOURCES

TABLE 1.4-1. UNCONTROLLED EMISSION FACTORS FOR NATURAL GAS COMBUSTION[a]

Furnace size & type (10^6 Btu/hr heat input)	Particulate[b]		Sulfur dioxide[c]		Nitrogen oxides[d]		Carbon monoxide[e]		Volatile organics			
									Nonmethane		Methane	
	kg/10^6 m^3	lb/10^6 ft^3	kg/10^6 m^3	lb/10^6 ft^3	kg/10^6 m^3	lb/10^6 ft^3	kg/10^6 m^3	lb/10^6 ft^3	kg/10^6 m^3	lb/10^6 ft^3	kg/10^6 m^3	lb/10^6 ft^3
Utility boilers (> 100)	16 - 80	1 - 5	9.6	0.6	8800[h]	550[h]	640	40	23	1.4	4.8	0.3
Industrial boilers (10 - 100)	16 - 80	1 - 5	9.6	0.6	2240	140	560	35	44	2.8	48	3
Domestic and commercial boilers (< 10)	16 - 80	1 - 5	9.6	0.6	1600	100	320	20	84	5.3	43	2.7

[a]Expressed as weight/volume fuel fired.
[b]References 15-18.
[c]Reference 4. Based on avg. sulfur content of natural gas, 4600 g/10^6 Nm^3 (2000 gr/10^6 scf).
[d]References 4-5, 7-8, 11, 14, 18-19, 21.
[e]Expressed as NO_2. Tests indicate about 95 weight % NO_x is NO_2.
[f]References 4, 7-8, 16, 18, 22-25.
[g]References 16, 18. May increase 10 - 100 times with improper operation or maintenance.
[h]For tangentially fired units, use 4400 kg/10^6 m^3 (275 lb/10^6 ft^3). At reduced loads, multiply factor by load reduction coefficient in Figure 1.4-1. For potential NO_x reductions by combustion modification, see text. Note that NO_x reduction from these modifications will also occur at reduced load conditions.

TABLE 1.3-1. UNCONTROLLED EMISSION FACTORS FOR FUEL OIL COMBUSTION

EMISSION FACTOR RATING: A

Boiler Type[a]	Particulate Matter[b]		Sulfur Dioxide[c]		Sulfur Trioxide		Carbon Monoxide[d]		Nitrogen Oxide[e]		Volatile Organics[f] Nonmethane		Methane	
	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$
Utility Boilers														
Residual Oil	[g]	[g]	19S	157S	0.34S[h]	2.9S[h]	0.6	5	8.0 (12.6)(5)[i]	67 (105)(42)[i]	0.09	0.76	0.03	0.28
Industrial Boilers														
Residual Oil	[g]	[g]	19S	157S	0.24S	2S	0.6	5	6.6[j]	55[j]	0.034	0.28	0.12	1.0
Distillate Oil	0.24	2	17S	142S	0.24S	2S	0.6	5	2.4	20	0.024	0.2	0.006	0.052
Commercial Boilers														
Residual Oil	[g]	[g]	19S	157S	0.24S	2S	0.6	5	6.6	55	0.14	1.13	0.057	0.475
Distillate Oil	0.24	2	17S	142S	0.24S	2S	0.6	5	2.4	20	0.04	0.34	0.026	0.216
Residential Furnaces														
Distillate Oil	0.3	2.5	17S	142S	0.24S	2S	0.6	5	2.2	18	0.085	0.713	0.214	1.78

[a] Boilers can be approximately classified according to their gross (higher) heat rate as shown below:
- Utility (power plant) boilers: $>106 \times 10^9$ J/hr ($>100 \times 10^6$ Btu/hr)
- Industrial boilers: 10.6×10^9 to 106×10^9 J/hr (10×10^6 to 100×10^6 Btu/hr)
- Commercial boilers: 0.5×10^9 to 10.6×10^9 J/hr (0.5×10^6 to 10×10^6 Btu/hr)
- Residential furnaces: $<0.5 \times 10^9$ J/hr ($<0.5 \times 10^6$ Btu/hr)

[b] References 3-7 and 24-25. Particulate matter is defined in this section as that material collected by EPA Method 5 (front half catch).

[c] References 1-5. S indicates that the weight % of sulfur in the oil should be multiplied by the value given.

[d] References 3-5 and 8-10. Carbon monoxide emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.

[e] Expressed as NO_2. References 1-5, 8-11, 17 and 26. Test results indicate that at least 95% by weight of NO_x is NO for all boiler types except residential furnaces, where about 75% is NO.

[f] References 18-21. Volatile organic compound emissions are generally negligible unless boiler is improperly operated or not well maintained, in which case emissions may increase by several orders of magnitude.

[g] Particulate emission factors for residual oil combustion are, on average, a function of fuel oil grade and sulfur content:
- Grade 6 oil: $1.25(S) + 0.38$ kg/10^3 liter [$10(S) + 3$ lb/10^3 gal] where S is the weight % of sulfur in the oil. This relationship is based on 81 individual tests and has a correlation coefficient of 0.65.
- Grade 5 oil: 1.25 kg/10^3 liter (10 lb/10^3 gal)
- Grade 4 oil: 0.88 kg/10^3 liter (7 lb/10^3 gal)

[h] Reference 25.

[i] Use 5 kg/10^3 liters (42 lb/10^3 gal) for tangentially fired boilers, 12.6 kg/10^3 liters (105 lb/10^3gal) for vertical fired boilers, and 8.0 kg/10^3 liters (67 lb/10^3 gal) for all others, at full load and normal (>15%) excess air. Several combustion modifications can be employed for NO_x reduction: (1) limited excess air can reduce NO_x emissions 5-20%, (2) staged combustion 20-40%, (3) using low NO_x burners 20-50%, and (4) ammonia injection can reduce NO_x emissions 40-70% but may increase emissions of ammonia. Combinations of these modifications have been employed for further reductions in certain boilers. See Reference 23 for a discussion of these and other NO_x reducing techniques and their operational and environmental impacts.

[j] Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are strongly related to fuel nitrogen content, estimated more accurately by the empirical relationship:
kg $NO_2/10^3$ liters $= 2.75 + 50(N)^2$ [lb $NO_2/10^3$gal $= 22 + 400(N)^2$] where N is the weight % of nitrogen in the oil. For residual oils having high (>0.5 weight %) nitrogen content, use 15 kg $NO_2/10^3$ liter (120 lb $NO_2/10^3$gal) as an emission factor.

PB89-194229

United States
Environmental Protection
Agency

Office of Air Quality
Planning And Standards
Research Triangle Park, NC 27711

EPA-450/2-89-001
April 1989

AIR

EPA

ESTIMATING AIR TOXICS EMISSIONS FROM COAL AND OIL COMBUSTION SOURCES

TABLE 4-1. SUMMARY OF TOXIC POLLUTANT EMISSION FACTORS FOR OIL COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^{12}$ Btu) Residual Oil	Distillate Oil
Arsenic	19	4.2
Beryllium	4.2	2.5
Cadmium	15.7	10.5
Chromium	21	48
Copper	280	280
Lead	28[c]	8.9[d]
Mercury	3.2	3.0
Manganese	26	14
Nickel	1260	170
POM	8.4[b]	22.5
Formaldehyde	405[e]	405[e]

[a]All emission factors are uncontrolled, and are applicable to oil-fired boilers and furnaces in all combustion sectors unless otherwise noted.

[b]This value was calculated using all available residual oil data given in Table 4-35. If the upper end of the range of available data is excluded when calculating an average value (which could be used in this table), the average factor for POM from residual oil combustion becomes 4.1 $lb/10^{12}$ BTU.

[c]Applicable to utility boilers only.

[d]Applicable to industrial, commercial, and residential boilers.

[e]The formaldehyde factors are based on very limited and relatively old data. Consult Table 4-37 and accompanying discussion for more detailed information.

PB81-225559

Emissions Assessment of Conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources

TRW, Inc.
Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

1981

U.S. Department of Commerce
National Technical Information Service

TABLE 61. COMPARISON OF EXISTING TRACE ELEMENT EMISSION FACTOR DATA WITH RESULTS OF CURRENT STUDY OF OIL-FIRED INDUSTRIAL COMBUSTION SOURCES, pg/J

	Distillate oil-fired boilers			Residual oil-fired boilers			
		Existing data			Existing data		
Element	Current study	Ref. 42	Ref. 43	Current study	Ref. 42	Ref. 21	Ref. 28
Aluminum (Al)	178	15	250	177	156	87	132
Arsenic (As)	3.5	1.3	1.5	1.2	9.1	18	12
Barium (Ba)	1.2	8.4	16	3.3	9.5	29	31
Calcium (Ca)	75	845	450	229	780	320	1428
Cadmium (Cd)	1.3	2.5	11	0.66	0.2	52	6.9
Cobalt (Co)	3.6	2.3	1.0	11	23	50	10
Chromium (Cr)	24	36	29	29	50	30	21
Copper (Cu)	37	205	160	10	93	64	350
$\boxed{\text{Fluorine (F)}}$	—	$\boxed{14}$	—	—	1.0	2.7	149
Iron (Fe)	363	545	140	83	379	411	453
Mercury (Hg)	—	1.7	1.2	—	1.9	0.9	1.5
Potassium (K)	85	60	230	261	213	777	392
Lithium (Li)	0.5	1.5	1.2	1.1	1.0	1.4	1.7
Magnesium (Mg)	42	40	210	24	111	297	2384
Nickel (Ni)	255	112	290	728	804	964	433
Lead (Pb)	24	48	42	2	7	80	34
Antimony (Sb)	—	1.7	5.7	—	21	10	25
Silicon (Si)	735	173	—	8655	1610	400	595
Vanadium (V)	195	30	2.9	366	250	3656	714
Zinc (Zn)	42	40	110	33	46	29	66

Ave. 50.9

UF COGENERATION PROJECT
EXAMPLE CALCULATIONS - NATURAL GAS

ROWS listed below correspond to the ROW listed in Table.

Table A-1: (Note: all other data not calculated but supplied by manufacturer)

ROW 13--Heat Input (10^6BTU/hr):

Power (kw) x Heat Rate (10^6BTU/kwh)

$43{,}262.0 \times 8{,}043/10^6 = 348.0 \times 10^6$ BTU/hr

ROW 14--Natural Gas (lb/hr):

Heat Input (10^6BTU/hr) ÷ Fuel Heat Content (BTU/lb)

$348.0 \times 10^6 \div 19{,}000 = 18{,}313.5$ lb/hr

Note: 19,000 is input as 0.019 since heat input is in 10^6BTU, i.e. 348.0

ROW 15--Natural Gas (CF/hr):

Heat input (10^6BTU/hr) ÷ Heat content (BTU/CF)

$348.0 \times 10^6 \div 946 = 367{,}818.5$ CF/hr

ROW 21--Volume Flow (acfm) - See Note A in emission factors and calculations:

$V = mRT/PM$

1,036,552 lb/hr x 1,545 x (785 + 460°K) ÷ (27.8 x 2,116.8 lb/ft^2) ÷ 60(min/hr)

= 564,678 acfm

ROW 22--Volume Flow (scfm) - See Note A:

Same as ROW 21 except adjusted for standard temperature of 68°F

1,036,552 lb/hr x 1,545 x (941 + 68°K) ÷ (27.8 x 2,116.8) ÷ 60

= 239,478 scfm

ROW 32--Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

564,678 (acfm) x (257 +460°K) ÷ (785 ÷ 460°K)

= 325,200 acfm

ROW 35--Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

325,200 ft^3/min ÷ 60 ÷ (10^2 ÷ 4 x 3.14159)

= 72.59 ft/sec

<u>Table A-2</u>:

ROWS 59, 64, 69, 75, 81, 118, 156, and 159--(Except Duct Burner) :

Emissions in Tons per year; example for particulate:

2.5 lb/hr x 8,760 hrs/yr ÷ 2,000 lb/ton

= 10.95 ton/yr

For Duct Burner and Oil Firing capacity factors were used. Example for duct burner:
1.87 lb/hour x 0.30 x 8,760 ÷ 2,000 = 2.46 tons per year.

ROW 63--SO_2 Emissions (lb/hr):

367,818.5 cf/hr x 1 gr ÷ 7,000 gr/lb x 2 lb SO_2/lbS ÷ 100 cf

= 2.82 lb/hr

ROW 68--NO_x Emissions (lb/hr) - See Note B:

25 ppm x [20.9 ÷ 5.9 (1 - 6.1/100) - 14.4] x 2,116.8 lb/ft^2 x 564,678 ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr ÷ [1,545 x (785 + 460°K) x 10^6 (adjust for ppm)]

= 35.0 lb/hr

ROW 74 and 80--CO, VOC Emissions (lb/hr) - See Note C example for VOC shown:

4 ppm x (1-6.1/100) x 564,678 acfm x 2,116.8 lb/ft^2 x 12 (molecular wgt. of carbon)

x 60 min/hr ÷ (1,545 x (785 +460) + 10^6)

= 1.59 lb/hr

Table A-3:

Emission factors for oil presented in Table 4-1 of EPA (1989) multiplied by heat input; example for arsenic: 382.6 x 10^6 Btu/hour x 4.216/10^{12} Btu = 0.0016 lb/hour

ROW 117--H_2SO_4 Mist Emission (lb/hr):

Based on 5 percent SO_2 converted to acid mist

1.05 lb SO_2/hr x 0.05 x 98 ÷ 64 (or a ratio 3.06/2)

= 8.04 x 10^2

Table A-4:

Emission factor multiplied by heat input

U.S. DEPARTMENT OF COMMERCE
National Technical Information Service

PB-296 390

Emission Assessment of Conventional Stationary Combustion Systems; Volume II Internal Combustion Sources

TRW, Inc, Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab, Research Triangle Park, NC

Feb 1979

Best Available Copy

TABLE 52. COMPARISON OF TRACE ELEMENT EMISSION FACTORS FOR DISTILLATE OIL-FUELED GAS TURBINES AND DISTILLATE OIL ENGINES

Trace Element	Mean Emission Factor, pg/J	
	Distillate Oil Fueled Gas Turbine	Distillate Oil Reciprocating Engine
Aluminum	64	66
Antimony	9.4	12
Arsenic	2.1	2.2
Barium	8.4	14
Beryllium	0.14	0.03
Boron	28	11
Bromine	1.8	4.0
Cadmium	1.8	3.1
Calcium	330	237
Chromium	20	26
Cobalt	3.9	5.7
Copper	578	453
Iron	256	325
Lead	25	26
Magnesium	100	44
Manganese	145	16
Mercury	0.39	0.13
Molybdenum	3.6	12.5
Nickel	526.	564
Phosphorus	127	97
Potassium	185	179
Selenium	2.3	2.1
Silicon	575	301
Sodium	590	1625
Tin	35	9.1
Vanadium	1.9	0.95
Zinc	294	178

EPA-450/2-88-006
October 1988

Toxic Air Pollutant Emission Factors—A Compilation For Selected Air Toxic Compounds And Sources

By
Anne A. Pope
Air Quality Management Division
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

Patricia A. Cruse
Claire C. Most
Radian Corporation
Research Triangle Park, North Carolina 27709

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office Of Air And Radiation
Office Of Air Quality Planning And Standards
Research Triangle Park, North Carolina 27711

October 1988

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Scotch marine boilers, distillate oil	10300501	POM		17.7 pg/J	Uncontrolled	114
Oil combustion		Cast iron sectional boilers, distillate oil	10300501	POM		<14.9 pg/J	Uncontrolled, home heating application	114
Oil combustion		Hot air furnace, distillate oil	10300501	POM		<0.14 pg/J	Uncontrolled, same reference also lists <15.4 for same boiler/fuel type	114
Oil combustion	49	Boiler flue gas	1	Tetrachlorodibenzo-p-dioxin, 2,3,7,8-	1746016	Not detectable	Low ash, 2% sulfur oil, sampled after heat exch., before ESP, 2378-TCDD detec. limit=<4.2-<7.9 ng/m3	119
Oil combustion	49	Flue gas	1	Tetrachlorodibenzofuran, 2,3,7,8-	51207319	Not detectable	Low ash, 2% sulfur oil, sampled after heat exch., before ESP, 2378-TCDD detec. limit=<0.67-<1.3ng/m3	119
Oil combustion, commercial		Residual oil-fired tangential furnaces	103004	Vanadium	7440622	3660 pg/J	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, commercial		Residual oil-fired wall furnaces	103004	Vanadium	7440622	3660 pg/J	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, commercial		Tangential furnace, residual oil	103004	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Wall furnace, residual oil	103004	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Scotch marine boilers, residual oil	10300401	POM		0.95 pg/J heat input	Uncontrolled, represents benzo(a)pyrene only	114
Oil combustion, commercial		Distillate oil-fired tangential furnaces	103005	Vanadium	7440622	30.0 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Distillate oil-fired wall furnaces	103005	Vanadium	7440622	30.0 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Tangential furnace, distillate oil	103005	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54

Page 4-162

January 30, 1992

RECEIVED
JAN 31 1992
Division of Air
Resources Management

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

RE: Alachua County--A.P.
UF Cogeneration Project
AC 01-204652

Attention: John Reynolds

Dear Mr. Fancy:

Pursuant to our discussion of January 15, 1992, this correspondence provides additional information concerning nitrogen oxides (NO_x) emission calculations for the University of Florida boilers. As we discussed, it is my opinion that the use of Figure 1.4-1 from AP-42 is not technically appropriate and can produce significant errors. This chart reflects instantaneous load conditions and cannot appropriately account for average operating conditions. Moreover, given the Department's latitude in implementing its regulations, there is no obligation for the Department to use this figure given the uncertainty in its origin and appropriateness to the existing boilers.

Presented in Table 1 is the average fuel usage for Units 3 and 5 for 1988, 1989, and 1990. The average load factor on gas can be calculated directly using fuel usage and hours of operation data presented in the annual operation report. The maximum fuel usage at 100 percent load is specified as cubic feet per hour for each boiler in Specific Condition 1 of each permit. The effective full load operation can be calculated by dividing the total fuel usage by the potential full load fuel usage. The equivalent full load operating hours can be used to calculate average load using the actual operating hours given in the annual operating reports. Adjustments of oil usage are made by subtracting the hours used on oil from the total hours. This calculation is somewhat uncertain since the load factor for oil is also unknown.

The load factors for natural gas presented in Table 1 are different than those calculated and presented in the Department's December 31, 1991 letter. The difference in calculating load factors using two independent methods are as high as about 25 percent. This is one source of error that can be introduced.

Another source of error is using the load coefficients as a means of calculating an average weighted emission factor. Table 2 presents this comparison. This table presents the load reduction coefficient and emission factor as a function of load (taken from Figure 1.4-1). The table also presents some possible operating conditions in terms of the percent of operation at a specific load. For example, if 50 percent

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

KBN

of the time the boiler operated at 100 percent load and 50 percent of the time it operated at 40 percent load then the average weighted load when operating would be 70 percent. The average weighted emission factor can then be calculated by using the specific emission factors for each load. The table also lists the emission factor obtained directly from Figure 1.4-1 using the average weighted load. This example calculation clearly indicates that the appropriate emission factor would be 20 percent higher than an emission factor calculated using an average load. Table 2 presents other examples that clearly indicate an error introduced by using Figure 1.4-1. Since there are no available data to determine the various instantaneous load conditions during the year, the use of Figure 1.4-1 is not technically appropriate. Indeed, all operating reports submitted for natural gas firing from electric utilities over the last 10 years use the emission factor in Table 1.4-1.

The errors introduced when calculating the average load factor and when calculating the average weighted emission factor clearly suggest that using Figure 1.4-1 is inappropriate. There are several other factors that should also be considered.

The Department should also be aware that under Rule 17-2.100(3)(b) Florida Administrative Code, allowable emissions can be specified as actual emissions as long as the limits are federally enforceable. Current interpretation suggests that the existing limits are federally enforceable, since the units in question (Units 3 and 5) have received BACT determinations.

Table 3 presents comparison of potential and requested emissions of NO_x for various scenarios. The permit application requested a 94 percent reduction in potential NO_x emissions from the existing boilers. The request was based on obtaining sufficient emission reductions from the existing units to eliminate the need for PSD review of NO_x. With this strategy the requested potential emissions of NO_x, including the CT/duct burner and limited operation of existing Units 4 and 5, are 298.37 tons per year. This is a decrease in potential emissions of over 800 tons per year or 278 percent. Without this strategy of taking NO_x reductions from Units 4 and 5, there is no need to take any operating limits for Units 4 and 5. Under this scenario, the potential NO_x emissions from Units 4 and 5 are 502 tons per year or 7.8 times higher than originally requested for these units. Clearly the operating limitations proposed in the permit have significant environmental advantages over other scenarios.

Your consideration in this matter is appreciated. Please call if you have any questions.

Sincerely,

Robert C. McCann Jr
for

Kennard F. Kosky, P.E.
President

KFK/tyf

cc: Scott Osbourn
C. Reynolds
C. Holladay
G. Kutyna, NE Dist
J. Harper, EPA
C. Shaver, NPS
BA/PL

91062A1/5

Table 1. UF Heating Plant Fuel Use, Hours of Operation and Average Calculated Load Factor

Unit	Year	Fuel Use		Operation at Full Load		Actual Hours	Load Factor Gas/Oil
		Gas (Mcf)	Oil (gal)	Gas (hrs)	Oil (hrs)		
Unit 3	1988	464,100	26,268	3,033.3	24.6	4,451.6	68.77%
	1989	392,375	11,269	2,564.5	10.6	5,057.2	50.89%
	1990	248,350	19	1,623.2	0.0	2,648.1	61.30%
	Avg.	368,275	12,519	2,407.0	11.7	4,052.3	59.69%
Unit 5	1988	537,506	537,506	3,277.5	503.9	6,411.0	58.83%
	1989	403,205	28,481	2,458.6	26.7	4,549.9	54.57%
	1990	416,485	5,557	2,539.5	5.2	5,115.6	49.73%
	Avg.	452,399	190,515	2,758.5	178.6	5,358.8	54.50%

Table 2. Calculated Emission Factors Under Possible Operating Conditions

Load	Load Reduction Coefficient	Emission Factor (lb/mmcf)	Percent at Load	Percent at Load	Percent at Load	Percent at Load	Percent at Load
100%	1.00	550	50%		65%	75%	
95%	0.90	495					70%
90%	0.81	446		70%			
85%	0.74	407					
80%	0.67	369					
75%	0.60	330					
70%	0.55	303					
65%	0.51	281					
60%	0.48	264					
55%	0.43	237					
50%	0.40	220					
45%	0.37	204					
40%	0.35	193	50%				
35%	??	188					
30%	??	180			35%		
25%	??	172					
20%	??	164					
15%	??	156					
10%	??	148		30%			
5%	??	140				25%	30%
Average Load =			70%	66%	76%	76%	68%
Average Emission Factor =			371	356	421	448	389
Figure 1.4-1 Factor =			303	285	338	338	294
Difference =			20%	22%	22%	28%	28%

Table 3. Comparison of Existing and Proposed Potential Emissions for the UF Cogeneration Project

Unit	Potential Emissions (tons/year)	Requested Emissions (tons/year)	Emission Reduction (tons/year)	Decrease
1	128.4	0.0	(128.4)	100%
2	128.4	0.0	(128.4)	100%
3	368.6	0.0	(368.6)	100%
4	107.0	5.5	(101.5)	95%
5	395.1	59.0	(336.1)	85%
Total:	1,127.5	64.5	(1,063.0)	94%
Cogen Only	233.9	233.9	NA	NA
w/Cogen and 4&5 Reductions		298.4	(829.1)	278%
w/Cogen and No 4&5 Reductions	736.0		(327.0)	44%
Emissions Increase (without reductions) in Units 4&5		437.6 tons/year 147%		

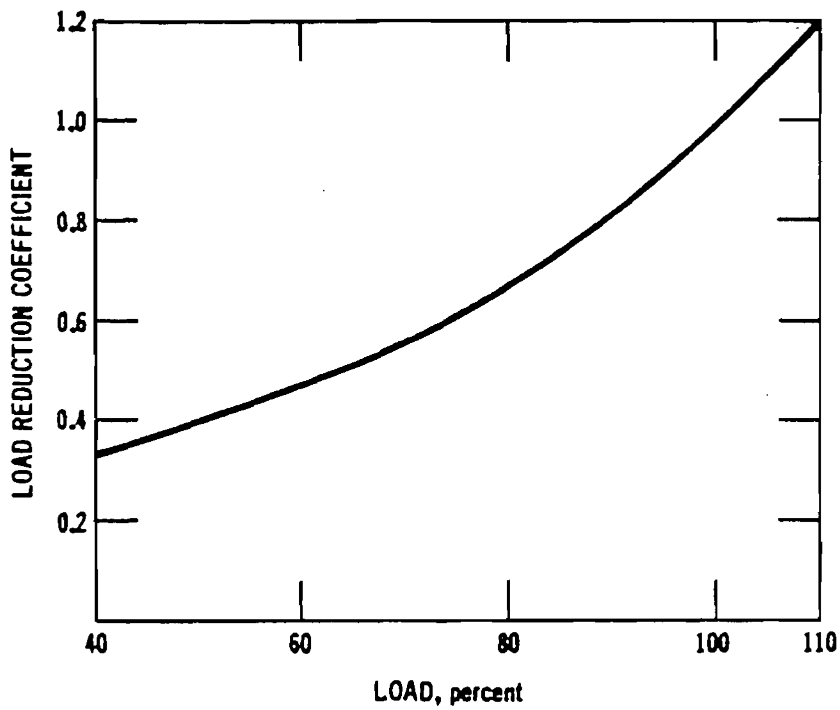

Figure 1.4-1. Load reduction coefficient as function of boiler load. (Used to determine NO_x reductions at reduced loads in large boilers.)

References for Section 1.4

1. D. M. Hugh, et al., Exhaust Gases from Combustion and Industrial Processes, EPA Contract No. EHSD 71-36, Engineering Science, Inc., Washington, DC, October 2, 1971.

2. J. H. Perry (ed.), Chemical Engineer's Handbook, 4th Edition, McGraw-Hill, New York, NY, 1963.

3. H. H. Hovey, et al., The Development of Air Contaminant Emission Tables for Non-process Emissions, New York State Department of Health, Albany, NY, 1965.

4. W. Bartok, et al., Systematic Field Study of NO_x Emission Control Methods for Utility Boilers, APTD-1163, U. S. Environmental Protection Agency, Research Triangle Park, NC, December 1971.

Florida Department of Environmental Regulation
Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400
Lawton Chiles, Governor   Carol M. Browner, Secretary

January 16, 1992

Mr. Greg Worley
Air Enforcement Branch
EPA Region IV
345 Courtland Street NE
Atlanta, Georgia 30365

Re: Permit Application AC 01-204652, PSD-FL-181
University of Florida Cogeneration Project

Dear Mr. Worley:

EPA's guidance is needed to resolve an issue with the above PSD permit application. A copy of the application was forwarded to EPA last November. The issue is whether or not to allow emission offset credits for Boilers 3 and 5 as if they had been run at full load. Data from the operation reports show that the boilers did not run at full load during the years in question.

The applicant wants us to disregard the emission factor adjustment called for in AP-42, Figure 1.4-1, for Boilers 3 and 5 so they can escape PSD review for NO_x. They want us to use the discretion provided for in Florida Administrative Code, Rule 17-2.100(3)(b), to presume that their actual boiler emissions were equal to the allowable emissions which were based on full load operation.

We were advised by Ron Ryan, OAQPS, that the AP-42, Table 1.4-1 emission factor should not be applied without adjustment for load according to Figure 1.4-1. The applicant argues that Figure 1.4-1 should apply only to instantaneous determinations and should not be used where long term averaging is involved.

Any input EPA may provide will be appreciated. If more clarification is needed, please contact John Reynolds of our staff at 904-488-1344.

Sincerely,

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

CHF/JR/plm

Florida Department of Environmental Regulation
Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400
Lawton Chiles, Governor
Carol M. Browner, Secretary

January 9, 1992

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. R. W. Neiser
Senior Vice President-Legal and Gov. Affairs
Florida Power Corporation
3201-34th Street South
St. Petersburg, Florida 33733

Dear Mr. Neiser:

Re: Permit Application AC 01-204652, PSD-FL-181

The Department received Florida Power Corporation's letter dated January 2, 1992, and considers it a partial response to one issue in the Department's incompleteness letter of December 31, 1991. The additional information requested below applies only to this one issue concerning NO_X emission factors.

In the absence of NO_X emission test data for the years in question, please provide the following data for Boilers Nos. 3 and 5 at the University of Florida facility:

1. Boiler and burner manufacturer, address and phone number.
2. Date boilers were manufactured and date installed.
3. Boiler and burner type/configuration (provide sketch).
4. Design maximum heat input rate.
5. Full description and dates of all burner modifications, if any.

If clarification is needed on any of the above, please contact the permit engineer, John Reynolds, at (904) 488-1344.

Sincerely,

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

CHF/JR/plm

c: S. Osbourn, FPC
K. Kosky, P.E., KBN
A. Kutyna, NED (w/Jan. 2 ltr)
J. Harper, EPA (" ")
C. Shaver, NPS (" ")

P 832 538 764

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PS Form 3800, June 1990

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- 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.
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Mr. R. W. Neiser
Senior Vice President-Legal and Gov. Affairs
Florida Power Corporation
3201 - 34th Snreet South
St. Petersburg, FL 33733

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PS Form 3811, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

RECEIVED
JAN 16 1992
Division of Air Resources Management

JAN -8 1992

Mr. John Reynolds
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Dear Mr. Reynolds:

To confirm our telephone conversation of January 8, 1992 regarding NO_x emissions estimates for natural gas fired boilers, the load reduction coefficient determined from Figure 1.4-1 of AP-42 should be used in conjunction with the utility boiler factors in Table 1.4-1 to estimate emissions accurately. In addition, the estimates will be more accurate if the load percent used represents a fairly constant level, rather than an average of a widely varying load level. Thus, if estimates were made for several representative periods with different loads and summed the result should be more accurate than using a single average load for the entire period. Removing the hours that the boiler was not operating from the averaging period is the first and probably the largest improvement that could be made to the estimate's accuracy.

I could not find a detailed derivation of Figure 1.4-1 in our background documentation files, although it appears that references 7 and 14 of AP-42 section 1.4 contain a large amount of relevant data. Please call if I can be of further assistance.

Sincerely,

Ronald Ryan

Ronald Ryan
Environmental Engineer
Emission Factors and Methodologies Section

Florida Department of Environmental Regulation

Northeast District • Suite B200, 7825 Baymeadows Way • Jacksonville, Florida 32256-7577

Lawton Chiles, Governor

Carol M. Browner, Secretary

January 7, 1992

Mr. Scott Osborn
Florida Power Corporation
Post Office Box 14042
St. Petersburg, Florida 33733

Alachua County - AP
Florida Power Corporation
Cogen Project at U of Fl.

Dear Mr. Osborn:

The applications for transfer of permits enclosed are being returned per the January 06 (Patty Adams and Johnny Cole) teleconference.

The $250.00 for the transfer fees is to be refunded under separate cover.

The cogen certificate is to address the transfer of permits issue.

If there are any questions, please contact Johnny Cole at the letterhead address/telephone number.

Sincerely,

Andrew G. Kutyna

Andrew G. Kutyna, P.E.
District Air Program
Administrator

AGK:JC:bt

cc: Patty Adams, DARM, BAR

Department of Environmental Regulation

Routing and Transmittal Slip

To: (Name, Office, Location)

1. Patty Adams
2. DARM BAR
3.
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Remarks:

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JAN 9 1992
Division of Air
Resources Management

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AC 01-204652
PSD-FL-181

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JAN 3 1992
Division of Air Resources Management

Florida Power
CORPORATION

January 2, 1992

Mr. Barry Andrews
Bureau of Air Regulation
Florida Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Rd.
Tallahassee, Florida 32399-2400

Dear Barry:

Re: University of Florida Cogeneration Project

This letter is in response to questions by your staff regarding the proper application of the NO_x emission factor for natural gas-firing of external combustion sources (AP-42 Section 1.4). Table 1.4-1 presents a NO_x emission factor for utility boilers of 550 lb/10^6 ft^3 of natural gas fired. A footnote to this factor directs the user to "multiply the factor by the load reduction coefficient in Figure 1.4-1 at reduced loads."

As I am the author of the current AP-42 section, I am compelled to submit additional information for your consideration regarding the intent of Figure 1.4-1 within the context of this section. Section 1.4 was originally published in 1973 and included Figure 1.4-1. At that time, no reference was supplied for the figure. When I revised the section in 1982 (the current version is dated October 1986 and reflects some minor editorial changes made to the 1982 version), the figure was retained, although no reference could be identified. The rationale was that the figure may prove helpful for more accurately estimating an instantaneous or short-term emissions rate -- where the load (in percent) required for application of this figure may be readily available. You will note that the figure does not cite application of a "load factor" or a "capacity factor", rather an instantaneous representative load, in percent.

The AP-42 document is a compilation of emission factors, which are average values derived by averaging available data of acceptable quality. These factors are routinely applied in many contexts (e.g., to estimate the collective emissions from a number of sources, as in emission inventories; to predict emissions from new or proposed sources; to obtain annual or short-term emission estimates; etc.) and the document emphasizes that care should be taken to apply each factor in a manner consistent with its intended use.

To help users understand the reliability and accuracy of AP-42 emission factors, each factor is assigned a rating (A through E, with A being the best) which reflects the quality and the amount of data on which the factors are based. In general, factors based on many observations or on more widely accepted test procedures are assigned higher rankings. For instance, an emission factor based on 10 or more source tests on different plants would likely get an A rating, if all tests were conducted using a single valid reference measurement method or equivalent techniques (AP-42, Introduction, p.2). All NO_x emission factors in Section 1.4 have been assigned A ratings.

Given this background, it is my belief that in calculating annual NO_x emissions estimates from a natural gas-fired utility boiler, it is appropriate to apply only the factor provided in Table 1.4-1. Precedent has been set for such an interpretation in numerous applications, some of which have been reviewed by your staff. However, in order to confirm the appropriateness of the use of Figure 1.4-1, I have had discussions with Mr. Ron Ryan of the Emission Factor and Methodologies Section, Emission Inventory Branch, of the Office of Air Quality Planning and Standards. (Mr. Ryan may be contacted at (919) 541-4330.) Mr. Ryan stated that the origin and proper application of Figure 1.4-1 were, at best, unclear. He added that it might be best to apply such a figure to short-term emission estimates only, and contends that such an interpretation is supported by the practical difficulty of obtaining a representative "load" to apply to an annual emission estimate.

If you should have any questions, or wish to meet to discuss this issue in more detail, please do not hesitate to contact me at (813) 866-5158.

Sincerely,

Scott H. Osbourn
Environmental Engineer

cc: Preston Lewis, FDER
Ron Ryan, OAQPS
John Reynolds
Cleve Holladay
Jewell Harper, EPA
Chris Shaver, NPS
Chuck Collins, CD

1/3/92 RRN

File Copy

Florida Department of Environmental Regulation

Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

December 31, 1991

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. R. W. Neiser
Senior Vice President-Legal and Gov. Affairs
Florida Power Corporation
3201-34th Street South
St. Petersburg, Florida 33733

Dear Mr. Neiser:

Re: Permit Application AC 01-204652
UF Cogeneration Project

The subject application and permit fees for the UF cogeneration facility were received by this office on December 2, 1991, after a pre-application meeting on November 13 with FPC staff. About two weeks later FPC staff contacted us to inquire about the status of the application. They emphasized the urgency of the project. We indicated to them that our review had not been completed but that we hoped an incompleteness letter might be avoided. Several days later we discovered that PSD applicability for one of the major pollutants (NO_x) was determined incorrectly in the application. We notified your staff and consultants of this by phone on December 19. In order to complete the application, the following additional information and revisions are required:

1. The AP-42 NO_x emission factor for fully loaded natural gas-fired boilers over 100 MMBtu/hr is 550 lbs. NO_x/MM ft^3 of fuel fired. For loads less than 100%, the emission factor is reduced according to AP-42, Figure 1.4-1. The 100% factor was used to calculate offset credits of 195.1 tons/yr of NO_x emissions, thus arriving at a net NO_x increase of 38.8 tons/yr. This level of net emissions (less than 40 tons/yr) would preclude PSD review for NO_x as stated in the application. However, analysis of load factors for UF's boilers Nos. 3 and 5 (capacity over 100 MMBtu/hr) during the three year period '88 - '90 reveals the following:

Fuel MM ft^3 per yr./Operating hrs per yr.

	'88	'89	'90
No. 3	464.1/4451.6	392.4/5057.2	248.4/2648.1
No. 5	537.8/6411	403.2/4549.9	416.8/5115.6

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Dividing the fuel rates by the operating hours gives the following (assume approximately 1,000 Btu required per pound of steam and 946 Btu per ft^3):

Avg. ft^3/hr. (000) / Avg. lbs. Steam per hr. (000)

	'88	'89	'90
No. 3	104.3/98.7	77.6/73.4	93.8/88.7
No. 5	83.9/79.4	88.6/83.8	81.5/77.1

Average load factors are obtained by dividing the steam production by the maximum capacity of 120,000 lbs/hr. The load reduction coefficient is then obtained from AP-42, Figure 1.4-1:

Avg. % Load/Load Reduction Coefficient

	'88	'89	'90
No. 3	82/.65	61/.47	74/.60
No. 5	66/.50	70/.55	64/.49

NO_x emission factors are then obtained by multiplying the load reduction coefficients by the 100% load factor, i.e. 550:

NO_x Emission Factor (lbs/MM ft^3 fuel)

	'88	'89	'90
No. 3	358	259	330
No. 5	275	303	270

A weighted average emission factor for the 3 yr. period can be based on relative operating hours as follows:

Fraction of Total hrs/Emission Factor

	'88	'89	'90	Total
No. 3	.37/132.5	.42/108.8	.21/69.3	310.6
No. 5	.40/110	.28/84.8	.32/86.4	281.2

Thus the NO_x emission credits would be approximately 155 tons/yr instead of the 195.1 tons/yr claimed, resulting in a net increase of about 79 tons/yr instead of 38.8 tons/yr. Due to the above, the application will have to be revised to include PSD review for NOx.

2. References in the application to the proposed facility being major on the basis of emissions exceeding 250 tons per year should be changed to 100 tons per year since the HRSG is on the "List of 28" major source categories (fossil fuel boiler exceeding 250 MMBtu/hr input including GT exhaust).

3. Page 2 of Form 1.202(1), Item C., implies "low NO_x combustors" are being proposed which is not the case. The revised application should explain that Low-NO_x combustors are not currently available for this model turbine but may be within 5 years. The revision should explain what is required in the initial design to provide for future installation of Low-NO_x burners.

4. Emission calculations are not adequately shown in Appendix A. All calculations affecting emissions should be shown in their entirety. For example, the Appendix "A" calculation for the NSPS NO_x emission limit of 75 ppm corrected to 15 percent oxygen is not carried to completion. The set-up is shown, but not the final calculation. The application should clearly show how all emission-related quantities were obtained.

5. Total steam production should be shown in Table 1-1 along with design capacity of the HRSG.

6. Please evaluate the impact of this project on the following Class I areas: Chassahowitzka National Wilderness Area in Florida and Okefenokee National Wilderness Area in Georgia. This evaluation should include a cumulative PM_{10} and NO_x Class I increment analysis. An expanded air quality related values analysis (AQRV) should be done since there are no significant impact levels for this analysis. The AQRV analysis includes impacts to soils, vegetation and wildlife.

7. Please explain the use of terrain elevations at receptor points in the modeling and show how the elevations input into the model were derived.

If further clarification is needed on any of the above, please contact John Reynolds or Cleve Holladay at (904) 488-1344.

Sincerely,

A. Preston Lewis
FOR
C. H. Fancy, P.E.
Chief
Bureau of Air Regulation

CHF/JR/plm

c: A. Kutyna, NED
K. Kosky, P.E., KBN
D. Jones, P.E., FPC
J. Harper, EPA
C. Shaver, NPS
Reading File
John Reynolds
Cleve Holladay
12/31/91 RBM

P 832 538 758

Certified Mail Receipt

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

UNITED STATES POSTAL SERVICE

Sent to Mr. R. W. Neiser	
Street & No. Senior VP-Legal & Gov. Affairs FL Power Corp.	
P.O., State & ZIP Code 3201-34th Street South St. Petersburg, FL 33733	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$
Postmark or Date mailed: 12/31/91 AC 01-204652 PSD-FL-181	

PS Form 3800, June 1990

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 next to the article number.

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. R. W. Neiser
Senior V.P.-Legal & Gov. Affairs
Florida Power Corp.
3201-34th Street South
St. Petersburg, Florida 33733

4a. Article Number
P 832 538 758

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

7. Date of Delivery JAN 02 1992

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form 3811, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

KBN

December 2, 1991

RECEIVED
DEC 3 1991
Division of Air
Resources Management

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

Subject: Alachua County - A.P.
University of Florida Cogeneration Project

Dear Clair:

This correspondence presents information discussed during the November 13, 1991 meeting concerning the above referenced project. As stated at the meeting, a three year period was used to calculate actual emissions for the existing University of Florida Heating Plant. Three years were used since the calendar year 1990 was abnormally warm compared with historical data. A quantitative measure of this is reflected by the number of heating degree days observed by the National Weather Service for Gainesville. In 1990, the heating degree days were 709 compared to a historical average of 1,259. The average heating degree days for 1990 and 1989 was 974 which would normally be considered the two year period identified in the Department's rules [Rule 17-2.100(3)(a)] as applicable for calculating actual emissions. However, this period was not representative of actual emissions. Therefore, a three year average of 1988 through 1990 was used to calculate actual emissions. The heating degree days for this period is 1,104 which is more representative of the operation of the UF heating plant.

As stated at the meeting, the use of a combined cycle configuration for the project will considerably reduce emissions through the use of an efficient combustion turbines and waste heat utilization. Over the twenty year life of the project, an average equivalent of about 374,110 barrels of oil will be saved by the project. The reduction in potential emissions by not using oil will be 107 tons per year (TPY) of PM10, 1,850 TPY of SO_2 and 432 TPY of NOx. In addition, the project will save the University of Florida an average of $5,244,00 per year over 20 years. Indeed, the environmental and economic benefits of the project make it highly advantageous.

91062A1/2

KBN ENGINEERING AND APPLIED SCIENCES, INC.
1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

KBN

Because of the need to proceed expeditiously with this project (i.e., construction start of February 1, 1991), your staff's expeditious review would be greatly appreciated. Please call if you have any questions.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

cc: Scott Osbourn
W.W. Vierday
Project File
J. Reynolds
C. Holladay
J. Cole, NE Dist
J. Harper, EPA
C. Shaver, NPS
BA/PL

RECEIVED
DER - MAIL ROOM
1991 DEC -2 PM 3:21

Florida Power
CORPORATION

November 25, 1991

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

Dear Mr. Fancy:

Re: University of Florida Cogeneration Project

With regard to our Scott Osbourn and your Patty Adams conversation on November 19, 1991, this is to supplement our filing on November 12, 1991. Enclosed are the original and four copies each of applications for transfer of permit for boilers Nos. 1, 2, 3, 4 & 5 at the Central Heat Plant, University of Florida. Also enclosed is a check in the amount of $2,750.00 which covers the $250.00 application fee for the transfer permits and the additional $2,500.00 to supplement the previous $5,000.00 check for the air construction permit.

On November 12, 1991, Florida Power Corporation submitted an application to construct a 43-megawatt (MW) cogeneration facility at the existing University of Florida (UF) Central Heat Plant. The proposed cogeneration facility will consist of a combustion turbine (CT) with a generating capability of 43 MW. The steam generated by heat recovery steam generators (HRSGs) will be used for injection into the turbine for emission control and exported to the UF thermal distribution system. One hundred percent of UF's steam requirements will be supplied by the cogeneration plant with existing UF boilers #4 & #5 utilized for back-up capacity.

Upon commercial operation of the cogeneration plant, FPC will be responsible for the operation and common control of the University Heat Plant #2 boilers. Boilers #1, #2, & #3 will be retired in place. Boilers #4 & #5 will be operated as back-up capacity as further documented in these applications. Ownership of all these boilers will remain with the University of Florida.

If you have any questions during the review process, please contact me at (813) 866-4511.

Sincerely,

K. L. Small for
W. W. Vierday, Manager
Environmental Programs-Licensing

Enclosures

pag/WWV6.Fancy2.Let

G. Reynolds
C. Holladay
G. Cole, NE Dist (w/ TO requests for AO permits)
BA/PL

Florida Power CORPORATION

ACCOUNTS PAYABLE DEPT. B3F
P. O. BOX 14042
ST. PETERSBURG, FL 33733-4042
(813) 866-5257

REMITTANCE ADVICE

89

CHECK DATE 11/22/91 VENDOR FLORIDA DEPARTMENT OF VENDOR NO. 284216 CHECK NO. 1367547

INVOICE NO.	DATE	OUR ORDER NO.	VOUCHER	GROSS AMOUNT	DISCOUNT	NET AMOUNT
DE1119275 CK66676	11/19/91		9111125914	2,750.00	.00	2,750.00
					TOTAL	2,750.00

001031

THE ATTACHED REMITTANCE IS IN FULL SETTLEMENT OF ACCOUNT AS STATED. IF NOT CORRECT PLEASE RETURN TO ABOVE ADDRESS.

Accounts Payable Department B3F
P.O. Box 14042
St. Petersburg, Fl 33733-4042

Florida Power
CORPORATION

63-027
631

DATE 11/22/91 CHECK NO. 1367547

PAY: $2*THOUSAND*750*DOLLARS AND 00 CENTS $*****2,750.00

NCNB National Bank of Florida
Tampa, Florida

Void after 60 days

TO THE ORDER OF

FLORIDA DEPARTMENT OF
ENVIRONMENTAL REGULATION
2600 BLAIR STONE RD
TALLAHASSEE FL 32399-2400

K E McDonald

[redacted]

November 25, 1991

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

Dear Mr. Fancy:

Re: University of Florida Cogeneration Project

With regard to our Scott Osbourn and your Patty Adams conversation on November 19, 1991, this is to supplement our filing on November 12, 1991. Enclosed are the original and four copies each of applications for transfer of permit for boilers Nos. 1, 2, 3, 4 & 5 at the Central Heat Plant, University of Florida. Also enclosed is a check in the amount of $2,750.00 which covers the $250.00 application fee for the transfer permits and the additional $2,500.00 to supplement the previous $5,000.00 check for the air construction permit.

On November 12, 1991, Florida Power Corporation submitted an application to construct a 43-megawatt (MW) cogeneration facility at the existing University of Florida (UF) Central Heat Plant. The proposed cogeneration facility will consist of a combustion turbine (CT) with a generating capability of 43 MW. The steam generated by heat recovery steam generators (HRSGs) will be used for injection into the turbine for emission control and exported to the UF thermal distribution system. One hundred percent of UF's steam requirements will be supplied by the cogeneration plant with existing UF boilers #4 & #5 utilized for back-up capacity.

Florida Department of Environmental Regulation
Twin Towers Office Bldg. • 2600 Blair Stone Road • Tallahassee, Florida 32399-2400
Lawton Chiles, Governor Carol M. Browner, Secretary

November 15, 1991

Mrs. Christine Shaver, Chief
Permit Review & Technical Support Branch
National Park Service-Air Quality Division
Post Office Box 25287
Denver, Colorado 80225

Dear Mrs. Shaver:

Re: Florida Power Corporation
University of Fla. Cogeneration Project
PSD-FL-181

Enclosed for your review and comment is the above referenced PSD permit application. If you have any comments or questions, please contact John Reynolds or Cleve Holladay at the above address or at (904)488-1344.

Sincerely,

Patricia G. Adams

Patricia G. Adams
Planner
Bureau of Air Regulation

PA/kt

enclosure

Florida Department of Environmental Regulation

Twin Towers Office Bldg. ● 2600 Blair Stone Road ● Tallahassee, Florida 32399-2400

Lawton Chiles, Governor

Carol M. Browner, Secretary

November 15, 1991

Ms. Jewell Harper, Chief
Air Enforcement Branch
U.S. EPA - Region IV
345 Courtland Street, NE
Atlanta, Georgia 30308

Dear Ms. Harper:

Re: Florida Power Corporation
University of Fla. Cogeneration Project
PSD-FL-181

Enclosed for your review and comment is the above referenced PSD permit application. If you have any comments or questions, please contact John Reynolds or Cleve Holladay at the above address or at (904)488-1344.

Sincerely,

Patricia G. Adams

Patricia G. Adams
Planner
Bureau of Air Regulation

PA/kt

enclosure

Florida Power
CORPORATION

November 12, 1991

RECEIVED
NOV 13 1991
Bureau of
Air Regulation

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

Dear Mr. Fancy:

RE: University of Florida Cogeneration Project

Enclosed please find five copies of the University of Florida Cogeneration Air Permit Application. Also enclosed is a check for the application fee of five thousand dollars ($5,000).

Florida Power Corporation is proposing to locate a 43-megawatt (MW) cogeneration facility at the existing University of Florida (UF) Central Heat Plant. The proposed cogeneration facility will consist of a combustion turbine (CT) with a generating capability of 43 MW. The steam generated by heat recovery steam generators (HRSGs) will be used for injection into the turbine for emission control and exported to the UF thermal distribution system. 100 percent of UF's steam requirements will be supplied by the cogeneration plant with existing UF boiler No. 4 and 5 utilized for back-up capacity.

The cogeneration plant will be located west of the existing UF Heat Plant #2 in the open area between the FPC substation and fuel oil storage tank farm. As part of the project, the large fuel oil tank (500,000 gallon) will be dismantled and removed.

Design specifications and emissions data are provided in the application. If you have any questions during the review process, please contact me at (813) 866-4511.

Sincerely,

W W Vierday

W.W. Vierday
Environmental & Licensing

CC: K. Kosky
E. Coffin
J. Reynolds
C. Holladay
A. Kutyna, NE Dist
J. Bunch, NE Dist Branch
J. Harper, EPA
C. Shaver, NPS

GENERAL OFFICE: 3201 Thirty-fourth Street South • P.O. Box 14042 • St. Petersburg, Florida 33733 • (813) 866-5151
A Florida Progress Company

$5,000 pd.
11-13-91
Recpt.# 180712

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

RECEIVED
NOV 13 1991
Bureau of
Air Regulation

AC 01-204652
PSD-FL-181

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: *Cogeneration Facility* [X] New[1] [ ] Existing[1]

APPLICATION TYPE: [X] Construction [ ] Operation [ ] Modification

COMPANY NAME: *Florida Power Corporation* 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) *UF Cogeneration Project*

SOURCE LOCATION: Street *Mowry Road, University of Florida* City *Gainesville*

UTM: East *369.4 km* North *3.279.3 km*

Latitude *29* ° *38* ' *23* "N Longitude *82* ° *20* ' *55* "W

APPLICANT NAME AND TITLE: *Florida Power Corporation; R.W. Neiser, Senior Vice President*

APPLICANT ADDRESS: *3201 34th Street South, St. Petersburg, FL 33733*

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of *Florida Power Corporation*

I certify that the statements made in this application for an *air 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: Patricia K. Blizzard

R.W. Neiser, Sr VP, Legal and Gov Affairs
Name and Title (Please Type)

Date: 11/12/91 Telephone No. *(813) 866-5784*

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 judgement, that

[1]See Florida Administration Code Rule 17-2.100(57) and (104)

Florida Power
CORPORATION

Richard W. Neiser
Senior Vice President
Legal and
Governmental Affairs

March 8, 1991

TO WHOM IT MAY CONCERN

Subject: Letter of Authorization

Please be advised that Patricia K. Blizzard, Director Environmental Services Department, and Mr. W. Jeffrey Pardue, Manager, Environmental Programs - Regulatory, are authorized to represent Florida Power Corporation in matters relating to necessary permits and reporting documentation required from regulatory authorities in the areas of air, water, power plant site certifications and transmission line certifications, or hazardous and solid materials issues.

Sincerely,

Richard W. Neiser

RWN:sp

Post Office Box 14042, St. Petersburg, Florida 33733 · 813-866-5784
A Florida Progress Company

the pollution control facilities, when properly maintained and operated, will discharge 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 Kennard F. Kosky

Kennard F. Kosky
Name (Please Type)

KBN Engineering and Applied Sciences, Inc.
Company Name (Please Type)

1034 NW 57th Street, Gainesville, FL 32605
Mailing Address (Please Type)

Florida Registration No. *14996* Date: 11/5/91 Telephone No. *(904) 331-9000*

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.

Construction of a cogeneration facility that consists of one combustion turbine and associated heat recovery steam generator; see Section 2.0 in PSD Application

B. Schedule of project covered in this application (Construction Permit Application Only)

Start of Construction *February 1, 1992* Completion of Construction *April 1, 1994*

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.)

The cost of control is integral to the design of the project; low NO_x combustors using wet injection and natural gas will reduce emission of air pollutants.

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

The facility will include five boilers, three of which will be shut down. The permit numbers for these sources are: AO01-136997 (Boiler 1), AO01-136998 (Boiler 2), AO01-136999 (Boiler 3), AO01-136570 (Boiler 4) and AO01-136570 (Boiler 5). See discussion in Section 2.3 of PSD Application.

E. Requested permitted equipment operating time: hrs/day *24*; days/wk *7*; wks/yr *52*;
If power plant, hrs/yr *8,760*; if seasonal, describe:
See Section 2.0

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? ______

b. If yes, has "Lowest Achievable Emission Rate" been applied? ______

c. If yes, list non-attainment pollutants. ______

2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. *YES*

3. Does the State "Prevention of Significant Deterioration" (PSD) requirement apply to this source? If yes, see Sections VI and VII. *YES*

4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? *YES*

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? ______

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.

PSD Permit Application is attached.

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable: *Not applicable*

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		

B. Process Rate, if applicable: (See Section V, Item 1) *Not applicable*

1. Total Process Input Rate (lbs/hr): ____________________

2. Product Weight (lbs/hr): ____________________

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary) *See Table 2-1 in PSD Permit application*

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/hr	T/yr	
SO_2	*197.5*	*20.0*	*0.8% Sulfur*	*316.1*	*197.5*	*20.0*	*See*
PM	*10*	*49.9*	*NA*	*NA*	*10*	*49.9*	*Figure 2-1*
NO_x	*66.3*	*234*	*126 ppmvd*	*198.9*	*66.3*	*234*	*in PSD*
CO	*70.5*	*415.2*	*NA*	*NA*	*70.5*	*415.2*	*Application*
VOC	*4.03*	*39.2*	*NA*	*NA*	*4.03*	*39.2*	

[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) *NSPS--0.8% sulfur oil and 75 ppmvd NO_x corrected for heat rate, i.e., 126 ppmvd; FDER Rule 17-2.660.*
[3]Calculated from operating rate and applicable standard.
[4]Emission, if source operated with~~out~~ control (See Section V, Item 3).

D. Control Devices: (See Section V, Item 4) ***See Section 4.0 in PSD Application***

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 ***See Table A-1 in PSD Permit Application***

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas-CT	*<367,818.5 CF*[a]	*367,818.5 CF*	*348 @ Operating Conditions*
Natural Gas-DB	*197,907.0 CF*[b]	*197,674.4 CF*	*187*
Fuel Oil-CT	*1,039.6 lb*[c]	*20,792.4 lb*	*382.6 Operating*

CT = comubstion turbine; DB = duct burner
*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, others--lbs/hr.
[a]*8,760 hr/yr;* [b]*7,884 hr/yr;* [c] *438 hr/yr*
Fuel Analysis:

Percent Sulfur: *NG = 1 grain/100 CF; oil = 0.5% sulfur* Percent Ash: *<0.1*

Density: *~7.2 for oil* lbs/gal Typical Percent Nitrogen: *<0.015*

Heat Capacity: *NG = 946 Btu/CF; Oil = 18,400* BTU/lb *132,480 (Oil)* BTU/gal

Other Fuel Contaminants (which may cause air pollution): *See Appendix A in PSD Permit Application*

F. If applicable, indicate the percent of fuel used for space heating.

Annual Average ________ Maximum ________

G. Indicate liquid or solid wastes generated and method of disposal.

All wastewaters generated from the plant will be discharged to the University of Florida wastewater treatment plant.

H. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: *93* ft. Stack Diameter: *9.75* ft.

Gas Flow Rate: *325,200[a]* ACFM *320,364[a]* DSCFM Gas Exit Temperature: *257* °F.

Water Vapor Content: *11.25 (Gas) 8.54 (Oil)* % Velocity: *72.6 (Gas) 71.5 (Oil)* FPS

[a] Gas Firing--see Table A-1 for more detail.

SECTION IV: INCINERATOR INFORMATION

Not applicable

Type of Waste	Type O (Plastics)	Type II (Rubbish)	Type III (Refuse)	Type IV (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 Diameter: ______ 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 devices: [ ] 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)]
   See Table A-1 in the PSD Application
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 Appendix A in PSD Application***
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   See Appendix A in the PSD Application
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 Table A-1 in the 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).
   See Appendix A in the PSD Application
6. An 8 ½" 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.
   See Figure 2-1 in the PSD Application
7. An 8 ½" 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 (Examples: Copy of relevant portion of USGS topographic map).
   See Figure 1-1 in the PSD Application
8. An 8 ½" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   See Figure 2-1 in the 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.
Application fee attached

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.

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? *See Section 4.2 in PSD Application.*

[*X*] Yes [ ] No *40 CFR Part 60 Subpart GG; Subpart Db.*

Contaminant	Rate or Concentration
NO_x - CT	*75 ppmvd corrected to 15% O_2 and heat rate*
SO_2 - CT	*0.8% sulfur*
NO_x - DB	*0.2 lb/10^6 Btu heat input*

B. Has EPA declared the best available control technology for this class of sources (If yes, attach copy)

[*X*] Yes [ ] No *See Section 4.0 in PSD Application*

Contaminant	Rate or Concentration

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration
See Section 4.0 in PSD Application	

D. Describe the existing control and treatment technology (if any).

1. Control Device/System:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

See Section 4.0 in PSD Application

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

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 Devices:

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:

2.

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.
[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.

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.

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:

F. Describe the control technology selected:

1. Control Device: 2. Efficiency:[1]

3. Capital Cost: 4. Useful Life:

5. Operating Cost: 6. Energy:[2]

7. Maintenance Cost: 8. Manufacturer:

9. Other locations where employed on similar processes:

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:

[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 *Not applicable--see Sections 3.4.2.2 and 5.2 in PSD Application.*

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 *See Section 6.0 in PSD Application*

1. ______ Year(s) of data from ______/______/______ to ______/______/______
month day year month day year

2. Surface data obtained from (location) ______________________

3. Upper air (mixing height) data obtained from (location) ______________________

4. Stability wind rose (STAR) data obtained from (location) ______________________

C. Computer Models Used *See Section 6.0 in PSD Application*

1. ______________________ Modified? If yes, attach description.

2. ______________________ 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.

D. Applicants Maximum Allowable Emission Data *See Section 6.0 in PSD Application*

Pollutant	Emission Rate	
TSP	______________________	grams/sec
SO^2	______________________	grams/sec

E. Emission Data Used in Modeling *See Section 6.0 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. *PSD Application attached*

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 Section 4.0 in 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 Section 4.0 in PSD Application*

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION FOR THE PROPOSED UNIVERSITY OF FLORIDA COGENERATION FACILITY

Prepared For:

Florida Power Corporation
3201 34th Street South
St. Petersburg, FL 33711

Prepared By:

KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville, FL 32605

November 1991
91062C1

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ACRONYMS AND ABBREVIATIONS
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AAQS	Ambient Air Quality Standards
As	arsenic
BACT	best available control technology
Be	beryllium
10^6 Btu/hr	million British thermal units per hour
CAA	Clean Air Act
CFR	Code of Federal Regulations
CO	carbon monoxide
CT	combustion turbine
EPA	U.S. Environmental Protection Agency
°F	degrees Fahrenheit
F.A.C.	Florida Administrative Code
FBN	fuel-bound nitrogen
FDER	Florida Department of Environmental Regulation
FL	Fluoride
FPC	Florida Power Corporation
ft	foot/feet
ft^3/yr	cubic feet per year
g/s	grams per second
GE	General Electric
GEP	good engineering practice
H_2SO_4	sulfuric acid
Hg	mercury
HRSG	heat recovery steam generators
HSH	highest, second highest
ISC	Industrial Source Complex
ISCLT	Industrial Source Complex Long-Term
ISCST	Industrial Source Complex Short-Term
KBN	KBN Engineering and Applied Sciences, Inc.
km	kilometer
kW	kilowatt
kWh/yr	kilowatt-hour per year
LAER	lowest achievable emission rate
lb/hr	pounds per hour
m	meter
MW	megawatt
NH_3	ammonia
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSCR	nonselective catalytic reduction
NSPS	New Source Performance Standards
NTL	No Threat Levels
NWS	National Weather Service

ACRONYMS AND ABBREVIATIONS
(Page 1 of 2)

AAQS	Ambient Air Quality Standards
As	arsenic
BACT	best available control technology
Be	beryllium
10^6 Btu/hr	million British thermal units per hour
CAA	Clean Air Act
CFR	Code of Federal Regulations
CO	carbon monoxide
CT	combustion turbine
EPA	U.S. Environmental Protection Agency
°F	degrees Fahrenheit
F.A.C.	Florida Administrative Code
FBN	fuel-bound nitrogen
FDER	Florida Department of Environmental Regulation
FL	Fluoride
FPC	Florida Power Corporation
ft	foot/feet
ft^3/yr	cubic feet per year
g/s	grams per second
GE	General Electric
GEP	good engineering practice
H_2SO_4	sulfuric acid
Hg	mercury
HRSG	heat recovery steam generators
HSH	highest, second highest
ISC	Industrial Source Complex
ISCLT	Industrial Source Complex Long-Term
ISCST	Industrial Source Complex Short-Term
KBN	KBN Engineering and Applied Sciences, Inc.
km	kilometer
kW	kilowatt
kWh/yr	kilowatt-hour per year
LAER	lowest achievable emission rate
lb/hr	pounds per hour
m	meter
MW	megawatt
NH_3	ammonia
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSCR	nonselective catalytic reduction
NSPS	New Source Performance Standards
NTL	No Threat Levels
NWS	National Weather Service

ACRONYMS AND ABBREVIATIONS
(Page 2 of 2)

PM	particulate matter
PM(TSP)	total suspended particulate matter
PM10	particulate matter less than or equal to 10 micrometers
ppm	parts per million
ppmvd	parts per million volume, dry
PSD	prevention of significant deterioration
SIP	State Implementation Plan
SO_2	sulfuric dioxide
TPH	tons per hour
TPY	tons per year
$\mu g/m^3$	micrograms per cubic meter
UF	University of Florida
UNAMAP	Users Network for Applied Modeling of Air Pollution
VOC	volatile organic compound

1.0 INTRODUCTION

Florida Power Corporation (FPC) is proposing to locate a 43-megawatt (MW) cogeneration facility at the existing University of Florida (UF) Central Heat Plant. The proposed site, which is located in Gainesville, Alachua County (Figure 1-1), will be under the common control of FPC when the cogeneration plant becomes operational. This includes the central heat plant that consists of 5 existing boilers; 3 boilers will be taken out of service and 2 boilers will be used as back-up. The proposed cogeneration facility will consist of a combustion turbine (CT) with a generating capability of 43 MW (Table 1-1). Steam generated by heat recovery steam generators (HRSGs) will be used to supply steam for UF. A plot plan for the facility is presented in Figure 1-2.

KBN Engineering and Applied Sciences, Inc. (KBN), has been contracted by FPC to provide air permitting services for the facility. Initially, preliminary analyses were performed to determine compliance with prevention of significant deterioration (PSD) increments and preconstruction de minimis monitoring levels for the proposed plant only. A full PSD review was then performed to determine whether significant air quality deterioration will result from the proposed facility and other PSD increment-consuming sources and to determine compliance with ambient air quality standards (AAQS). The PSD review included control technology review, source impact analysis, air quality analysis (monitoring), and additional impact analyses.

The proposed project will be a major facility because emissions of at least one regulated pollutant exceeds 250 tons per year (TPY). PSD review is required for these emissions and for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates. The potential emissions from the proposed project will exceed the PSD significant emission rates for carbon monoxide (CO), particulate matter with an aerodynamic diameter of 10 micrometers (PM10), and arsenic (As). Therefore, the project is subject to PSD review for these pollutants.

Table 1-1. Characteristics of the University of Florida Cogeneration Facility

Characteristic	Data
<u>Capacity (kW)</u>	
Combustion Turbine	43,262
<u>Equipment Characteristics</u>	
Type of CT	GE LM 6000
CT Heat Input (10^6 Btu/hr)	348
Duct Burner (10^6 Btu/hr)	187
Nitrogen Oxides Injection Steam, Natural Gas Firing (lb/hr)	31,402
Nitrogen Oxides Injection Water, Oil Firing (lb/hr)	22,504
<u>Fuels</u>	
CT, Natural Gas, Primary (ft^3/hr)	367,818.5
CT, Distillate Oil, Emergency Backup (gas curtailment only)(lb/hr)	20,792.4
Duct Burner, natural gas only (ft^3/hr)	197,674.4

Note: 10^6 Btu/hr = British thermal units per hour
CT = Combustion turbine
ft^3/hr = cubic feet per hour
GE = General Electric
HRSG = heat recovery steam generator
kW = kilowatt
lb/hr = pounds per hour

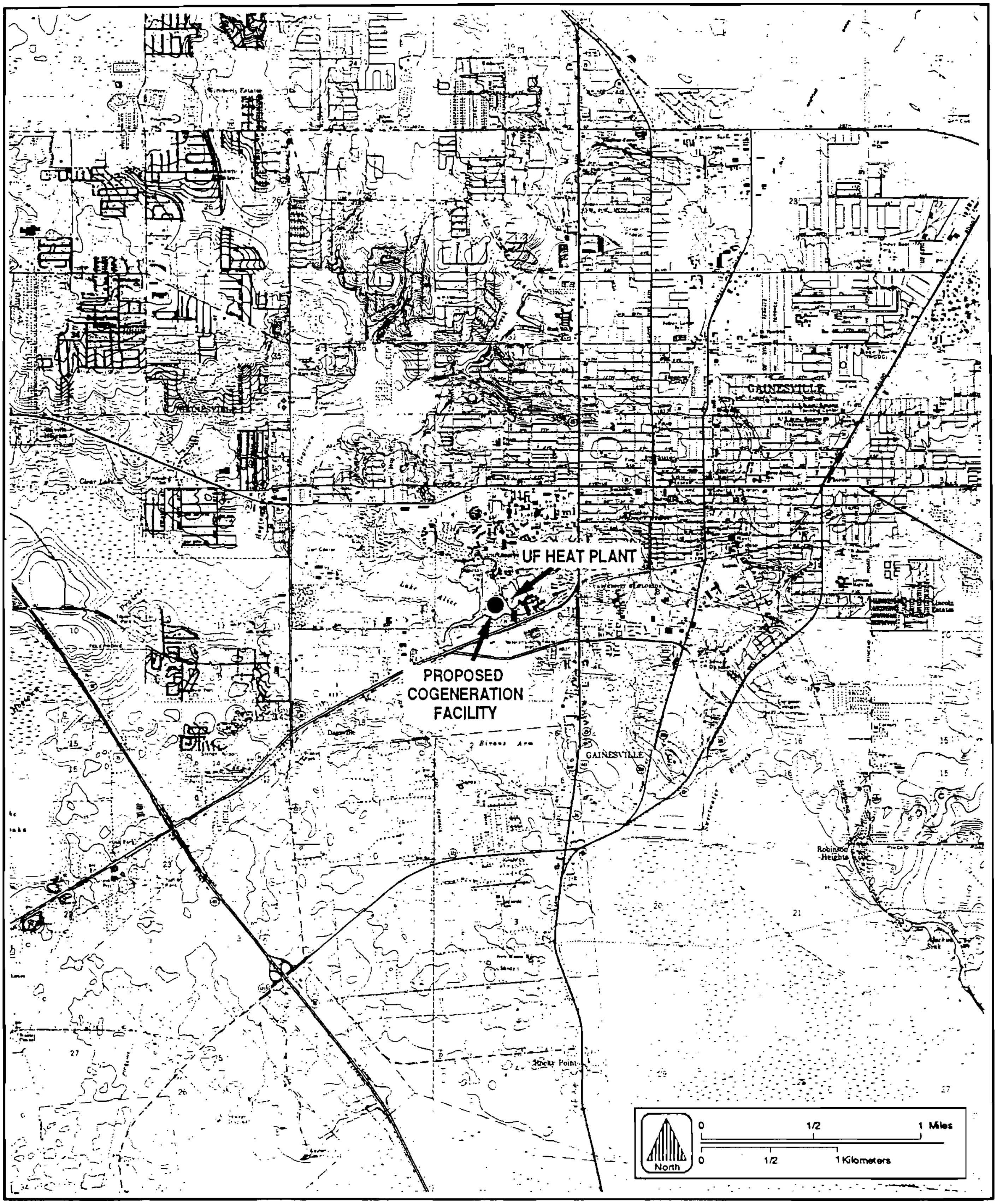

Figure 1-1 LOCATION OF UF COGENERATION FACILITY

KBN

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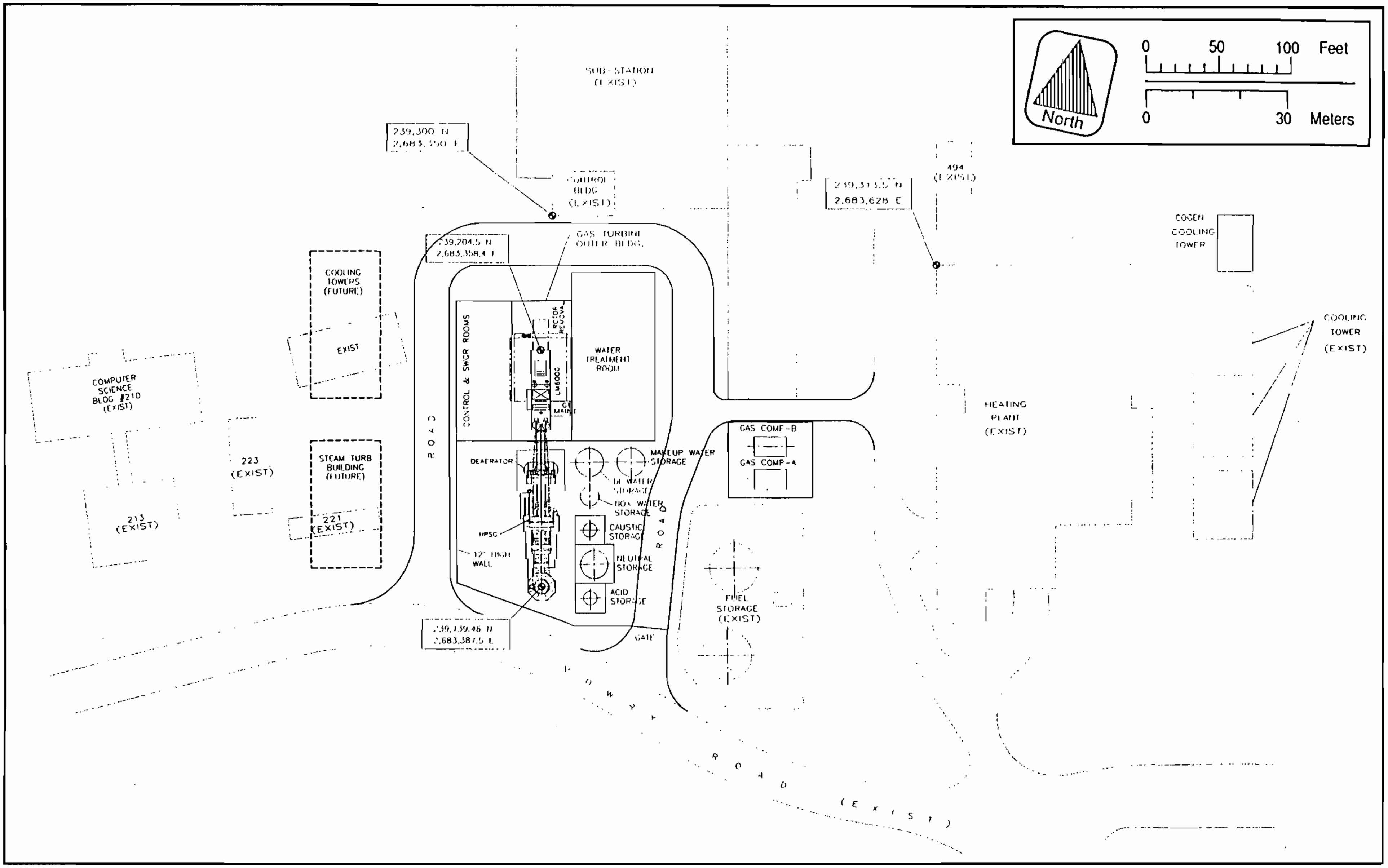


Figure 1-2 PLOT PLAN FOR UF COGENERATION FACILITY

KBN

This report is presented in seven sections. A general description of the proposed operation is given in Section 2.0. The air quality review requirements and applicability of the project to the PSD and nonattainment regulations are presented in Section 3.0. The control technology review for the project applicable under the U.S. Environmental Protection Agency's (EPA's) current top-down approach is discussed in Section 4.0. A discussion of the need for air quality monitoring data to satisfy the PSD preconstruction monitoring requirements is presented in Section 5.0. The air source impact analysis approach is presented in Section 6.0. The results of the air quality analyses and additional impact analyses associated with the project's impacts on vegetation, soils, and associated growth are discussed in Section 7.0.

2.0 PROJECT DESCRIPTION

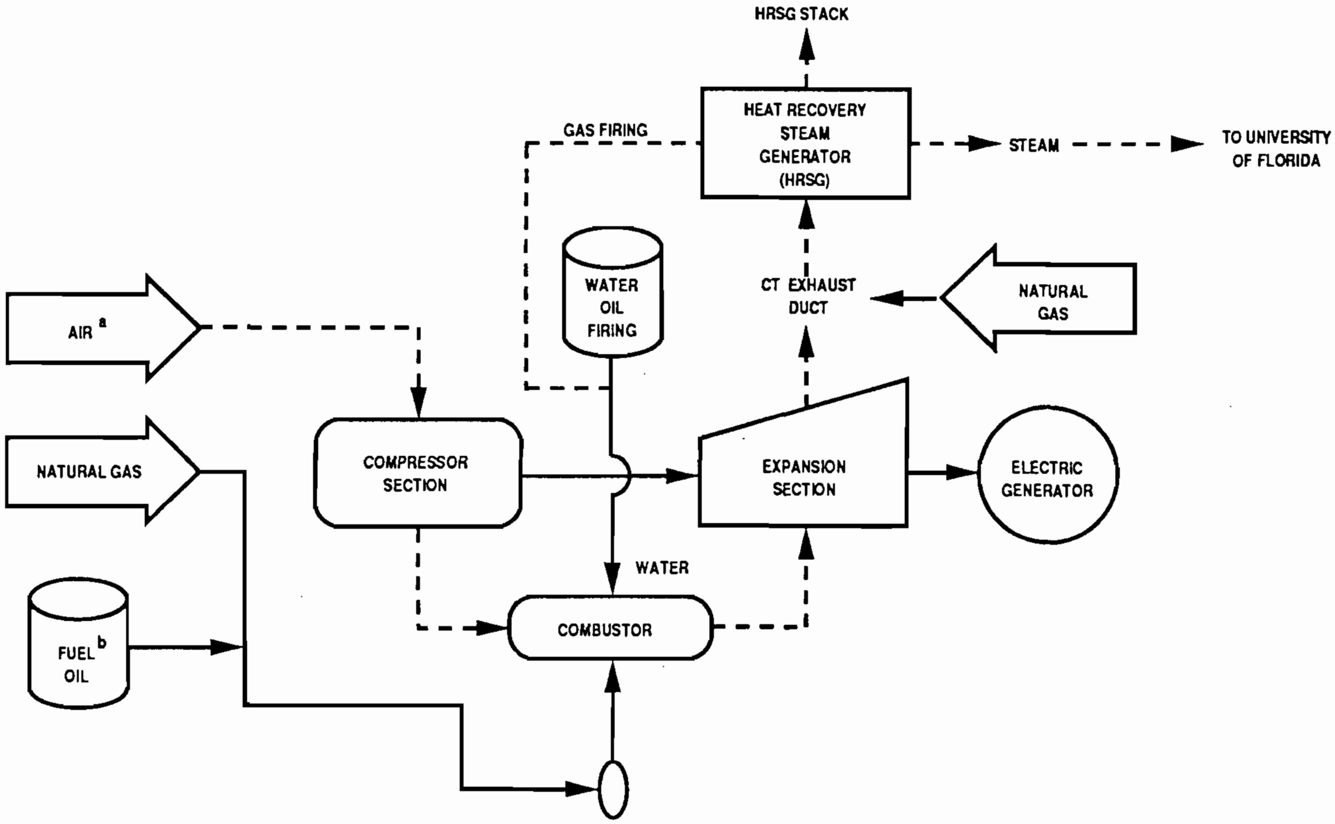
2.1 GENERAL DESCRIPTION

The proposed project will consist of installing one CT and one HRSG at the UF Central Heat Plant. The UF Central Heat Plant has five existing boilers which are primarily fired with natural gas with residual oil used as backup. The project will replace existing boilers 1, 2, and 3; Boilers 4 and 5 will be operated as back-up for the cogeneration plant. The existing boilers and cogeneration plant will be under the common control of FPC. Therefore, the "facility" for which PSD approval is requested includes the existing Central Heat Plant and the cogeneration plant. This is consistent with the term defined in Florida Department of Environmental Regulation (FDER) Rule 12-2.100(78) Florida Administrative Code (F.A.C.).

The CT will be the new General Electric (GE) LM 6000 machine. The LM 6000 is a newly developed aircraft derivative machine that has thermal efficiency of approximately 40 percent. This efficiency, developed from advanced aircraft compressor and turbine technology, makes the LM 6000 more efficient than the advanced heavy frame combustion turbine being offered by certain manufacturers (e.g., the GE Frame combustion turbine). A description of this machine is presented in Appendix A. The CT exhaust will go through the HRSG and exit to the atmosphere through an individual stack. There will be no bypass stack on the CT for simple cycle operation. A flow diagram of the project is presented in Figure 2-1.

The primary fuel for firing the CT will be natural gas; distillate fuel oil will be used as emergency backup when natural gas is curtailed. Operation with distillate oil will not exceed 438 hours per year. There will be supplementary firing of natural gas only in the HRSG.

Air emission sources associated with the proposed project consist of the CT and supplemental firing in the HRSG. Wet injection will be used to control



NOTES:

(a) COOLED FROM AMBIENT
(b) EMERGENCY BACKUP ONLY - 10 DAYS/YEAR

Figure 2-1 SIMPLIFIED FLOW DIAGRAM OF PROPOSED UNIT emissions of nitrogen oxides (NO_x) from the CT. The use of natural gas or low-sulfur (0.5-percent sulfur maximum) distillate fuel oil will minimize the emissions of sulfur dioxide (SO_2) from the unit.

2.2 FACILITY EMISSIONS AND STACK OPERATING PARAMETERS

The emissions and stack parameters for the CT are presented in Table 2-1. These data represent the maximum emissions since air inlet coolers may be installed on the CT to maintain a compressor temperature of 51°F, which will increase generating capability and regulate temperature. Maximum potential annual emissions for the project are presented in Table 2-2. Performance information and maximum emission rates for regulated criteria pollutants, regulated noncriteria pollutants, and nonregulated pollutants from the CT are presented in Tables A-1 through A-5 of Appendix A.

Supplemental firing with natural gas will take place in the duct between the CT and the HRSG. The supplemental firing, at a maximum rate of 187 million British thermal units per hour ($x\ 10^6$ Btu/hr), will allow the HRSG to produce additional steam. The firing of natural gas will produce additional air emissions, as shown in Tables 2-1 and 2-2, for the maximum firing rate. These emissions will combine with the CT exhaust gases only during natural gas firing and exhaust through the HRSG stack. Supplemental firing will be limited to an equivalent of 7,884 hours per year at maximum capacity (i.e., 1,474,308 $x\ 10^6$ Btu).

2.3 EXISTING FACILITY EMISSIONS

The proposed facility will include the existing Central Heat Plant which consists of five boilers firing natural gas and residual oil. Boilers 1, 2 and 3 will be taken out of service when the cogeneration plant becomes operational. Boilers 1 and 2 have heat input capacities of 88.5 million Btu per hour. Boiler 3 has a heat input capacity of 160.6 $x\ 10^6$ Btu/hr. Boilers 4 and 5 have heat input capacities of 71.7 and 172.2 $x\ 10^6$ Btu/hr and will be used only as back-up for the cogeneration plant. These boilers will be operated at lower capacity factors than in previous years. In addition, the use of residual oil in these boilers will be eliminated and

Table 2-1. Stack, Operating, and Emission Data for the UF Cogeneration Facility (Page 1 of 2)

	Fuel Type		
	Fuel Oil[a]	Natural Gas	
Parameter	Gas Turbine	Gas Turbine[b]	Duct Burner[c]
Stack Data (ft)			
Height	93	93	d
Diameter	9.75	9.75	d
Operating Data			
Temperature (°F)	257	257	d
Velocity (ft/sec)	71.5	72.59	d
Building Data (ft)			
Height	57	57	d
Length	54	54	d
Width	14	14	d
Maximum Hourly Emission Data (lb/hr) for Each Emission Unit/Fuel Type			
Sulfur Dioxide	197.5	1.05	0.56
Particulate Matter	10.0	2.5	1.87
Nitrogen Oxides	66.3	35.0	18.7
Carbon Monoxide	70.5	69.5	28.1
Volatile Organic Compounds	4.03	1.59	8.04
Sulfuric Acid Mist	3.3	Neg	Neg
Lead	0.0034	Neg	Neg
Annual Potential Emission Data (TPY) for Each Emission Unit/Fuel Type			
Sulfur Dioxide	43.3	4.6	2.23
Particulate Matter	2.2	10.95	7.37
Nitrogen Oxides	14.5	153.4	73.72

DB: $\frac{18.7 \text{ Lb/hr}}{185 \text{ mmBtu/hr}} = .1$ Lb/mmBtu

Table 2-1. Stack, Operating, and Emission Data for the UF Cogeneration Facility (Page 2 of 2)

Parameter	Fuel Type		
	Fuel Oil[a]	Natural Gas	
	Gas Turbine	Gas Turbine[b]	Duct Burner[c]
Carbon Monoxide	15.4	304.4	110.57
Volatile Organic Compounds	0.9	7.0	31.7
Sulfuric Acid Mist	3.5	Neg	Neg
Lead	0.00075	Neg	Neg

Note: °F = degrees Fahrenheit.
ft = feet.
ft/second = feet per second.
lb/hr = pounds per hour.
TPY = tons per year.

[a] Performance based on nitrogen oxide emissions of 42 parts per million by volume dry (corrected to 15 percent O_2); sulfur dioxide emissions based on an average sulfur content of 0.5 percent sulfur; annual emission data based on 438 hours per year.

[b] Performance based on nitrogen oxide emissions of 25 parts per million volume dry (corrected to 15 percent O_2); annual emissions data based on 8,760 hours/year (365 days per year) operation.

[c] Performance based on 187 x 10^6 Btu/hr heat input per heat recovery steam generators and 7,884 hours per year operation.

[d] Same as gas turbine natural gas; duct burners will not fire No. 2 oil.

Table 2-2. Maximum Annual Potential Emissions From Proposed Cogeneration Project

Pollutant	Fuel (TPY)			Total (TPY)
	Distillate Oil[a]	Natural Gas[b]		
		Gas Turbine	Duct Burner	
Sulfur Dioxide	43.3	4.4	2.2	49.9
Particulate Matter[c]	2.2	10.4	7.4	20.0
Nitrogen Oxide	14.5	145.7	73.7	233.9
Carbon Monoxide	15.4	289.2	110.6	415.2
Volatile Organic Compounds	0.9	6.7	31.7	39.2
Sulfuric Acid Mist	3.5	Neg	Neg	3.5
Lead	0.00075	Neg	Neg	0.00075

Note: Neg = negative.
PM10 = particulate matter with an aerodynamic diameter less than or equal to 10 micrometers.
TPY = tons per year.

[a]438 hours/year.
[b]95% capacity factor for gas turbine and 90% capacity for duct burner.
[c]PM10.

distillate oil, which will also be used as backup for the CT, will be used. Copies of the FDER permits are contained in Appendix B.

Because the facility consists of the Central Heat Plant, the net emissions decreases are creditable when evaluating PSD applicability [FDER Rule 17-2.500(2)(e)]. For the Central Heat Plant, the actual emissions representative of operation are presented in Table 2-3 for Boilers 1, 2, and 3, and Table 2-4 for Boilers 4 and 5. These emissions represent an average of the last complete 3-years (1988-90). A 3-year average is considered representative because operation of the Central Heat Plant is affected by meteorological conditions, i.e. heating and cooling requirements. A 3-year average is statistically more representative of the range of meteorological conditions that can influence steam demands. Copies of the annual operation reports are contained in Appendix B.

Since Boilers 4 and 5 will be operated as back-up for the cogeneration plant, the operation of these sources will be restricted based on the fuel use listed in Table 2-5. Also, the emission estimates in this table reflect the use of distillate oil rather than residual oil. This table also provides emissions for the fuel use proposed for these sources in the facility. These fuel limits will provide net emission decreases for the facility which are presented in Table 2-6.

Table 2-3. Actual Representative Emissions (1988-1990) of Regulated Pollutants, Boilers 1, 2, and 3 (Page 1 of 2)

	Boilers No. 1 & 2[a]		Boiler No. 3[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Natural Gas Burned[c]					
(MM ft^3/yr)	208		368		
No. 6 Fuel Oil[c]					
(gal/yr)		0		12,519	
(% sulfur)		0.964		1.85	
<u>Emission Factor</u>	lb/MM scf	lb/1,000 gal	lb/MM scf	lb/1,000 gal	
Particulate Matter	3	12.64[d]	3	21.5[d]	
Particulate Matter (PM10)	3	8.97[d]	3	15.27[d]	
Sulfur Dioxide	0.6	151.3[e]	0.6	290.5[e]	
Nitrogen Oxides	140	55	550	67	
Carbon Monoxide	35	5	40	5	
Volatile Organic Compounds (methane)	3	1	0.3	0.28	
Volatile Organic Compounds (nonmethane)	2.8	0.28	1.4	0.76	
Lead	Neg.	0.0042	Neg.	0.0042	
Fluorides	Neg.	0.052	Neg.	0.052	
Mercury	Neg.	0.00048	Neg.	0.00048	
Beryllium	Neg.	0.00063	Neg.	0.00063	
Arsenic	Neg.	0.0029	Neg.	0.0029	
Sulfuric Acid Mist	Neg.	2.32	Neg.	6.57	
<u>Emission Rate (TPY)</u>					
Particulate Matter	0.31	0.00	0.55	0.13	1.00
Particulate Matter (PM10)	0.31	0.00	0.55	0.10	0.96
Sulfur Dioxide	0.062	0.00	0.110	1.82	1.99
Nitrogen Oxides	14.57	0.00	101.28	0.42	116.26
Carbon Monixide	3.64	0.00	7.37	0.03	11.04

Table 2-3. Actual Representative Emissions (1988-1990) of Regulated Pollutants, Boilers 1, 2, and 3 (Page 2 of 2)

	Boilers No. 1 & 2[a]		Boiler No. 3[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Volatile Organic Compounds (methane)	0.31	0.00	0.06	0.00	0.37
Volatile Organic Compounds (nonmethane)	0.29	0.00	0.26	0.00	0.55
Lead	Neg.	0.0000	Neg.	0.0000	0.000
Total Fluorides	Neg.	0.000	Neg.	0.000	0.000
Mercury	Neg.	0.00000	Neg.	0.00000	0.000
Beryllium	Neg.	0.00000	Neg.	0.00000	0.00000
Arsenic	Neg.	0.0000	Neg.	0.0000	0.0000
Sulfuric Acid Mist	Neg.	0.00	Neg.	0.04	0.04

Note: ft^3/yr = cubic feet per year
gal/yr = gallons per year
% = percent
lb/mm = pounds per milimeter
scf = standard cubic feet
gal = gallons
Btu/hr = British thermal unit per hour
PM = particulate matte
PM10 = particulate matter (PM10)
TPY = tons per year

[a] Boilers 1 and 2 have heat input capacities less than 100 x 10^6 British thermal units per hour; therefore, emission factors for industrial boilers were used.
[b] Boiler 3 has a heat input capacity of greater than 100 x 10^6 British thermal units per hour; therefore, emission factors for utility boilers were used.
[c] Based on annual operating reports (see Appendix B).
[d] Based on equation: 10 S + 3, where S = sulfur content. PM10 is 71% of PM emissions.
[e] Based on equation: 157 S, where S = sulfur content.

Table 2-4. Actual Representative Emissions of Regulated Pollutants, Boilers 4 and 5 (Page 1 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Natural Gas Burned					
(MM ft^3/yr)	156		453		
No. 6 Fuel Oil					
(gal/yr)		55,207		190,515	
(% sulfur)		1.623		1.97	
<u>Emission Factor</u>	lb/MM scf	lb/1,000 gal	lb/MM scf	lb/1,000 gal	
Particulate Matter	3	19.23[d]	3	22.7[d]	
Particulate Matter (PM10)	3	13.65[d]	3	16.12[d]	
Sulfur Dioxide	0.6	254.8[e]	0.6	309.3[e]	
Nitrogen Oxides	140	55	550	67	
Carbon Monoxide	35	5	40	5	
Volatile Organic					
Compounds (methane)	3	1	0.3	0.28	
Volatile Organic					
Compounds (nonmethane)	2.8	0.28	1.4	0.76	
Lead	Neg.	0.0042	Neg.	0.0042	
Fluorides	Neg.	0.052	Neg.	0.052	
Mercury	Neg.	0.00048	Neg.	0.00048	
Beryllium	Neg.	0.00063	Neg.	0.00063	
Arsenic	Neg.	0.0029	Neg.	0.0029	
Sulfuric Acid Mist	Neg.	3.98	Neg.	7.0	
<u>Emission Rate (TPY)</u>					
Particulate Matter	0.23	0.53	0.68	2.16	3.61
Particulate Matter (PM10)	0.23	0.38	0.68	1.54	2.82
Sulfur Dioxide	0.05	7.03	0.14	29.46	36.68
Nitrogen Oxides	10.89	1.52	124.47	6.38	143.26
Carbon Monoxide	2.72	0.14	9.05	0.48	12.39
Volatile Organic					
Compounds (methane)	0.23	0.03	0.07	0.03	0.36

Table 2-4. Actual Representative Emissions of Regulated Pollutants, Boilers 4 and 5 (Page 2 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 6 Fuel Oil	Natural Gas	No. 6 Fuel Oil	Total
Volatile Organic Compounds (nonmethane)	0.22	0.01	0.32	0.07	0.61
Lead	Neg.	0.0001	Neg.	0.0004	0.0005
Fluorides	Neg.	0.0014	Neg.	0.0050	0.006
Mercury	Neg.	0.00001	Neg.	0.00005	0.00006
Beryllium	Neg.	0.00002	Neg.	0.00006	0.00008
Arsenic	Neg.	0.0001	Neg.	0.0003	0.0004
Sulfuric Acid Mist	Neg.	0.11	Neg.	0.67	0.78

Note: ft^3/yr = cubic feet per year
gal/yr = gallons per year
% = percent
lb/mm = pounds per milimeter
scf = standard cubic feet
gal = gallons
Btu/hr = British thermal unit per hour
PM = particulate matter
PM10 = particulate matter (PM10)
TPY = tons per year

[a] Boiler 4 has heat input capacity of less than 100 x 10^6 Btu/hr; therefore, emissions factors for industrial boilers were used.
[b] Boiler 5 has a heat input capacity of greater than 100 x 10^6 Btu/hr; therefore, emission factors for utility boilers were used.
[c] Based on annual operating reports (see Appendix B).
[d] Based on equation: 10 S + 3, where S = sulfur content. PM10 is 71% of PM emissions.
[e] Based on equation: 157 S, where S = sulfur content.

Table 2-5. Emissions of Regulated Pollutants for Boilers 4 & 5 After Commercial Operation of Cogeneration Plant (Page 1 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 2 Fuel Oil	Natural Gas	No. 2 Fuel Oil	Total
Natural Gas Burned[c]					
(MM ft^3/yr)	75		210		
No. 2 Fuel Oil[c]					
(gal/yr)		25,000		100,000	
(% sulfur)		0.5		0.5	
Emission Factor	lb/MM scf	lb/1,000 gal	lb/MM scf	lb/1,000 gal	
Particulate Matter	3	8[d]	3	8[d]	
Particulate Matter (PM10)	3	5.68[d]	3	5.68[d]	
Sulfur Dioxide	0.6	78.5[e]	0.6	78.5[e]	
Nitrogen Oxides	140	20	550	24	
Carbon Monoxide	35	5	40	5	
Volatile Organic Compounds (methane)	3	0.052	0.3	0.052	
Volatile Organic Compounds (nonmethane)	2.8	0.2	1.4	0.2	
Lead	Neg.	0.0013	Neg.	0.0042	
Fluorides	Neg.	0.0049	Neg.	0.052	
Mercury	Neg.	0.00045	Neg.	0.00048	
Beryllium	Neg.	0.00038	Neg.	0.00063	
Arsenic	Neg.	0.00063	Neg.	0.0029	
Sulfuric Acid Mist	Neg.	1.225	Neg.	1.225	
Emission Rate (TPY)					
Particulate Matter	0.11	0.10	0.32	0.40	0.93
Particulate Matter (PM10)	0.11	0.07	0.32	0.28	0.78
Sulfur Dioxide	0.02	0.98	0.06	3.93	4.99
Nitrogen Oxides	5.25	0.25	57.75	1.22[f]	64.47
Carbon Monoxide	1.31	0.06	4.20	0.25	5.83

Table 2-5. Emissions of Regulated Pollutants for Boilers 4 & 5 After Commercial Operation of Cogeneration Plant (Page 2 of 2)

	Boiler No. 4[a]		Boiler No. 5[b]		
	Natural Gas	No. 2 Fuel Oil	Natural Gas	No. 2 Fuel Oil	Total
Volatile Organic Compounds (methane)	0.11	0.00	0.03	0.00	0.15
Volatile Organic Compounds (nonmethane)	0.11	0.00	0.15	0.01	0.26
Lead	Neg.	0.0000	Neg.	0.0002	0.0002
Fluorides	Neg.	0.0001	Neg.	0.0026	0.003
Mercury	0.0000	0.0000	0.0000	0.0000	0.00003
Beryllium	Neg.	0.0000	Neg.	0.0000	0.00004
Arsenic	Neg.	0.0000	Neg.	0.0001	0.0002
Sulfuric Acid Mist	Neg.	0.02	Neg.	0.06	0.08

Note: ft^3/yr = cubic feet per year
gal/yr = gallons per year
% = percent
lb/mm = pounds per milimeter
scf = standard cubic feet
gal = gallons
Btu/hr = British thermal unit per hour
PM = particulate matter
PM10 = particulate matter (PM10)
TPY = tons per year

[a] Boiler 4 has a heat input capacity of less than 100 x 10^6 Btu/hr; therefore, emissions factors for industrial boilers were used.
[b] Boiler 5 has a heat input capacity of greater than 100 x 10^6 Btu/hr; therefore, emission factors for utility boilers were used.
[c] Based on annual operating reports (See Appendix A).
[d] Based on equation: 10 S + 3, where S = sulfur content. PM10 is 71% of PM emissions.
[e] Based on equation: 157 S, where S = sulfur content.
[f] Nitrogen oxides emissions based on ratio of residual and distillate oil emission factors.

Table 2-6. Net Emission Reductions From Boilers 1 through 5 at UF Central Heating Plant

	Net Emission Reduction (TPY)		
Pollutant	Boilers[a] 1, 2 and 3	Boilers[b] 4 and 5	Total
Particulate Matter	-1.00	-2.68	-3.68
Particulate Matter (PM10)	-0.96	-2.04	-3.00
Sulfur Dioxide	-1.99	-31.69	-33.68
Nitrogen Oxides	-116.26	-78.79	-195.05
Carbon Monoxide	-11.04	-6.56	-17.60
Volatile Organic Compounds (methane)	-0.37	-0.21	-0.58
Volatile Organic Compounds (nonmethane)	-0.55	-0.35	-0.90
Lead	-0.0000	-0.0003	-0.0003
Fluorides	-0.0003	-0.0037	-0.0041
Mercury	-0.00000	-0.00003	-0.00003
Beryllium	-0.00000	-0.00004	-0.00005
Arsenic	-0.0000	-0.0002	-0.0002
Sulfuric Acid Mist	-0.0411	-0.6999	-0.7410

Note: TPY = tons per year.

[a]Based on emissions in Table 2-1.
[b]Based on subtracting emissions in Table 2-2 from emissions in Table 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 proposed project. These regulations must be satisfied before the proposed cogeneration plant can begin operation.

3.1 NATIONAL AND STATE AAQS

The existing applicable national and Florida AAQS are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a preconstruction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA, and therefore PSD approval authority has been granted to the FDER.

A "major facility" is defined as any one of 28 named source categories that has the potential to emit 100 TPY or more, or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels ($\mu g/m^3$)

Pollutant	Averaging Time	AAQS[a] National Primary Standard	AAQS[a] National Secondary Standard	AAQS[a] State of Florida	PSD Increments[a] Class I	PSD Increments[a] Class II	Significant Impact Levels[b]
Particulate Matter (TSP)	Annual Geometric Mean	NA	NA	NA	5	19	1
	24-Hour Maximum	NA	NA	NA	10	37	5
Particulate Matter (PM10)	Annual Arithmetic Mean	50	50	50	4[c]	17[c]	1
	24-Hour Maximum	150	150	150	8[c]	30[c]	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum	365	NA	260	5	91	5
	3-Hour Maximum	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone	1-Hour Maximum[d]	235	235	235	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	15	NA	NA	NA

[a] Short-term maximum concentrations are not to be exceeded more than once per year.
[b] Maximum concentrations are not to be exceeded.
[c] Proposed October 5, 1989.
[d] Achieved when the expected number of days per year with concentrations above the standard is fewer than 1.

Note: Particulate matter (TSP) = total suspended particulate matter.
Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.

NA = Not applicable, i.e., no standard exists.

Sources: <u>Federal Register</u>, Vol. 43, No. 118, June 19, 1978.
40 CFR 50.
40 CFR 52.21.
Chapter 17-2.400, F.A.C.

A "major modification" is defined under PSD regulations as a change at an existing major facility that increases emissions by greater than significant amounts. PSD significant emission rates are shown in Table 3-2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21, Prevention of Significant Deterioration of Air Quality. The State of Florida has adopted PSD regulations that are essentially identical to federal regulations [Chapter 17-2.510, Florida Administrative Code (F.A.C.)]. Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new facility also must be reviewed with respect to Good Engineering Practice (GEP) stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 INCREMENTS/CLASSIFICATIONS

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality baseline concentration level of SO_2 and total suspended particulate matter [PM(TSP)] concentrations would constitute significant deterioration. The magnitude of the allowable increment 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. Initially, Congress promulgated areas as Class I (international parks,

Table 3-2. PSD Significant Emission Rates and De Minimis Monitoring Concentrations (Page 1 of 2)

Pollutant	Regulated Under	Significant Emission Rate (TPY)	De Minimis Monitoring Concentration[a] ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter (TSP)	NAAQS, NSPS	25	10, 24-hour
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Oxides	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 tons per year[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Asbestos	NESHAP	0.007	NM
Beryllium	NESHAP	0.0004	0.001, 24-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Vinyl Chloride	NESHAP	1	15, 24-hour
Benzene	NESHAP	[c]	NM
Radionuclides	NESHAP	[c]	NM
Inorganic Arsenic	NESHAP	[c]	NM

Table 3-2. PSD Significant Emission Rates and De Minimis Monitoring Concentrations (Page 2 of 2)

Pollutant	Regulated Under	Significant Emission Rate (TPY)	De Minimis Monitoring Concentration[a] ($\mu g/m^3$)

[a] Short-term concentrations are not be be exceeded.
[b] No de minimis concentration; an increase in volatile organic compounds emissions of 100 tons per year or more will require monitoring analysis for ozone.
[c] Any emission rate of these pollutants.

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below de minimis monitoring concentrations.

NAAQS = National Ambient Air Quality Standards.
NM = No ambient measurement method.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
$\mu g/m^3$ = micrograms per cubic meter.
TPY = tons per year.

Sources: 40 CFR 52.21.
Chapter 17-2, F.A.C.

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 be allowed greater deterioration than Class II areas, were designated. EPA then promulgated as regulations the requirements for classifications and area designations.

On October 17, 1988, EPA promulgated regulations to prevent significant deterioration as a result of emissions of NO_x and established PSD increments for nitrogen dioxide (NO_2) concentrations. The EPA class designations and allowable PSD increments are presented in Table 3-1. FDER has adopted the EPA class designations and allowable PSD increments for SO_2, PM(TSP), and NO_2 increments.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

1. The actual emissions representative of facilities in existence on the applicable baseline date; and
2. The allowable emissions of major stationary facilities that commenced construction before January 6, 1975, for SO_2 and PM(TSP) concentrations, or February 8, 1988, for NO_2 concentrations, but that were not in operation by the applicable baseline date.

The following emissions are not included in the baseline concentration and therefore affect PSD increment consumption:

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO_2 and PM(TSP)

concentrations, and after February 8, 1988, for NO_2 concentrations; and

2. Actual emission increases and decreases at any stationary facility occurring after the baseline date.

In reference to the baseline concentration, the term "baseline date" actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of SO_2 and PM(TSP), and February 8, 1988, in the case of NO_2,
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application, and
3. The trigger date, which is August 7, 1977, for SO_2 and PM(TSP), and February 8, 1988, for NO_2.

The minor source baseline date for SO_2 and PM(TSP) has been set as December 27, 1977, for the entire State of Florida (Chapter 17-2.450, F.A.C.).

3.2.3 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state 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 [Chapter 17-2.500(5)(c), F.A.C]. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in Chapter 17-2.100(25), F.A.C., as:

> An emissions limitation, including a visible emission 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 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.

BACT was promulgated within the framework of the PSD requirements in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's Guidelines for Determining Best Available Control Technology (BACT), (EPA, 1978) and in the PSD Workshop Manual (EPA, 1980). These guidelines were promulgated 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. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the same types of emissions unit 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. Therefore, BACT analyses must be conducted on a case-by-case basis."

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, as a minimum, demonstrate compliance with New Source Performance Standards (NSPS) for a source (if applicable). 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 decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a "bottom-up" approach consistent with the BACT Guidelines and PSD Workshop Manual has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program, including the adoption of a new "top-down" approach to BACT decisionmaking.

The top-down BACT approach essentially starts with the most stringent (or top) technology and emissions limit that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed facility and the facility on which the control technique was applied previously must be justified. Recently, EPA issued a draft guidance document on the top-down approach entitled Top-Down Best Available Control Technology Guidance Document (EPA, 1990).

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 CFR 52.21(m) and Chapter 17-2.500(f), F.A.C, any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

Ambient air monitoring for a period of up to 1 year generally is appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be used if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration (EPA, 1987a).

The regulations include an exemption that excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that FDER may exempt a proposed major stationary facility or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the de minimis levels presented in Table 3-2 [Chapter 17-2.500(3)(e), F.A.C.].

3.2.5 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source subject to PSD review for each pollutant for which the increase in emissions exceeds the significant emission rate (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication Guideline on Air Quality Models (Revised) (EPA, 1987b). The source impact analysis for criteria pollutants may be limited to the new or modified source if the net increase in impacts as a result of the new or modified source is below significance levels, as presented in Table 3-1.

Various lengths of record for meteorological data can be used for impact analysis. A S-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "highest, second-highest" (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If less than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

3.2.6 ADDITIONAL IMPACT ANALYSIS

In addition to air quality impact analyses, federal and State of Florida 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 [40 CFR 52.21; Chapter 17-2.500(5)(e), F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts as a result of general commercial, residential, industrial, and other growth associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

3.2.7 GOOD ENGINEERING PRACTICE STACK HEIGHT

The 1977 CAA Amendments require that the degree of emission limitation required for control of any 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). Identical regulations have been adopted by FDER [Chapter 17-2.270, F.A.C.]. GEP stack height is defined as the highest of:

1. 65 meters (m) (213 feet), or
2. A height established by applying the formula: $Hg = H + 1.5L$
   where: Hg = GEP stack height,
   H = Height of the structure or nearby structure, and
   L = Lesser dimension (height or projected width) of nearby structure(s), or
3. A height demonstrated by a fluid model or field study.

"Nearby" is defined 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 kilometer (km). Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula.

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Chapter 17-2.510, F.A.C.), all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review. A new major facility is required to undergo this review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant. A major modification at a major facility is required to undergo review if it results in a significant net emission increase of 40 TPY or more of the nonattainment pollutant or if the modification is major (i.e., 100 TPY or more).

For major facilities or major modifications that locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The area of influence is defined as an area that is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on Chapter 17-2.510(2)(a)2.a, F.A.C., all volatile organic compound (VOC) sources that are located within an area of influence are exempt from the provisions of new source review for nonattainment areas. Sources that emit other nonattainment pollutants and are located within the area of influence are subject to nonattainment review unless the maximum allowable emissions from the proposed source do not have a significant impact within the nonattainment area.

3.4 SOURCE APPLICABILITY

3.4.1 AREA CLASSIFICATION

The project site is located in Alachua County, which has been designated by EPA and FDER as an attainment area for all criteria pollutants. Alachua County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TSP), and NO_x. The site is located more than 100 km from the closest PSD Class I areas, i.e., the Chassahowitzka National Wilderness Area and Okefenokee National Wilderness Area.

3.4.2 PSD REVIEW

3.4.2.1 Pollutant Applicability

The proposed project is considered to be a modification to a major facility because the potential emissions of any regulated pollutant exceed 250 TPY; therefore, PSD review is required for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 3-2 (i.e., major modification). As shown, potential emissions from the proposed project will exceed the PSD significant emission rates for CO, PM10, and inorganic As. Therefore, the project is subject to PSD review for these pollutants.

3.4.2.2 Ambient Monitoring

Based on the net increase in emissions from the proposed project, presented in Table 3-3, a PSD preconstruction ambient monitoring analysis is required for PM10, CO, and As. However, if the net increase in impact of a pollutant is less than the de minimis monitoring concentration, then an exemption from the preconstruction ambient monitoring requirement is provided for in the FDER regulations [FDER Rule 17-2.500(3)(e)]. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

If preconstruction monitoring data are required to be submitted, data collected at or near the project site can be submitted, based on existing air quality data (e.g., FDER) or the collection of on-site data.

Maximum predicted impacts as a result of the net increase associated with the proposed project are presented in Table 3-4 for pollutants requiring PSD review. The methodology used to predict maximum impacts and the impact analysis results are presented in Sections 6.0 and 7.0. As shown in Table 3-4, the maximum net increase in impact is below the respective de minimis monitoring concentration for all pollutants. There is no acceptable ambient monitoring method for As; therefore, monitoring is not required for this pollutant.

Table 3-3. Net Increase in Emissions Due To the UF Cogeneration Facility Compared to the PSD Significant Emission Rates

Pollutant	Emissions (TPY) Potential Emissions From Proposed Turbines	Net Emission Reduction From Boilers 1-5	Increase Net Emissions	Significant Emission Rate	PSD Review
Sulfur Dioxide	49.9	33.7	16.2	40	No
Particulate Matter (TSP)	20.0	3.68	16.3	25	No
Particulate Matter (PM10)	20.0	3.00	17.0	15	Yes
Nitrogen Dioxide	233.9	195.1	38.8	40	No
Carbon Monoxide	415.2	17.6	397.6	100	Yes
Volatile Organic Compounds	39.2	0.90	38.3	40	No
Lead	0.00075	0.0003	0.00045	0.6	No
Sulfuric Acid Mist	3.5	0.74	2.8	7	No
Total Fluorides	0.0027	0.0041	-0.0014	3	No
Total Reduced Sulfur[a]	Neg	Neg	Neg	10	No
Reduced Sulfur Compounds[a]	Neg	Neg	Neg	10	No
Hydrogen Sulfide[a]	Neg	Neg	Neg	10	No
Asbestos[a]	Neg	Neg	Neg	0.007	No
Beryllium	0.00021	0.00005	0.0002	0.0004	No
Mercury	0.00025	0.00003	0.0002	0.1	No
Vinyl Chloride[a]	Neg	Neg	Neg	1	No
Benzene[a]	Neg	Neg	Neg	0	No
Radionuclides[a]	Neg	Neg	Neg	0	No
Inorganic Arsenic	0.00035	0.0002	0.00015	0	Yes

~40 TPY/boiler

Note: Neg = Negligible.
TPY = tons per year.
All calculations based on 59°F peak load condition.

[a]Emissions of these pollutants considered not to have any emission rate increase.
[b]Based on a maximum sulfur content specification of 0.1 percent in fuel oil.

Table 3-4. Predicted Net Increase in Impacts Due To the UF Cogeneration Facility Compared to PSD <u>De Minimis</u> Monitoring Concentrations

Pollutant	Concentration ($\mu g/m^3$) Predicted Net Increase Impacts[a]	<u>De Minimis</u> Monitoring Concentration
Particulate Matter (PM10)	4.63 (2.22)	10, 24-hour
Carbon Monoxide	42.4 (58.7)	575, 8-hour
Inorganic Arsenic	NA	NM

Note: NA = Not applicable.
NM = No acceptable ambient measurement method has been developed and, therefore, <u>de minimis</u> levels have not been established by EPA.

[a] TSP and PM10 impacts based on maximum emissions at 100-percent load and 100-percent capacity factor when firing oil, which will be limited to no more than about 18 days per year. Impacts for natural gas, the primary fuel, are shown in parentheses. Concentrations indicate the highest predicted values.

3.4.2.3 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m high. The proposed stack for the proposed turbine will be 93 feet (ft) in height (28.35 m) and, therefore, do not exceed the GEP stack height. The potential for downwash of the units' emissions caused by nearby structures is discussed in Section 6.0, Air Quality Modeling Approach.

3.4.3 NONATTAINMENT REVIEW

The project site is located in Alachua County, which is classified as an attainment area for all criteria pollutants. The plant is also located more than 50 km from any nonattainment area. Therefore, nonattainment requirements are not applicable.

3.4.4 HAZARDOUS POLLUTANT REVIEW

The FDER has promulgated guidelines (FDER, 1991) to determine whether any emission of a hazardous or toxic pollutant can pose a possible health risk to the public. All regulated pollutants for which an ambient standard does not exist and all nonregulated hazardous pollutants are to be compared to No Threat Levels (NTL) for each applicable pollutant. If the maximum predicted concentration for any hazardous pollutant is less than the corresponding NTL for each applicable averaging time, that emission is considered not to pose a significant health risk.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The control technology review requirements of the PSD regulations are applicable to emissions of PM10, CO, and inorganic As (see Section 3.0). This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to BACT analysis is based on the regulatory definitions of BACT, as well as EPA's current policy guidelines requiring the top-down approach.

4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for gas turbine are codified in 40 CFR 60, Subpart GG. These regulations apply to:

1. Electric utility stationary gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr [40 CFR 60.332 (b)];
2. Stationary gas turbines with a heat input at peak load between 10 and 100 x 10^6 Btu/hr [40 CFR 60.332 (c)]; or
3. Stationary gas turbines with a manufacturer's rate base load at ISO conditions of 30 MW or less [40 CFR 60.332 (d)].

The electric utility stationary gas turbine provisions apply to stationary gas turbines constructed for the purpose of supplying more than one-third of their potential electric output capacity for sale to any utility power distribution system [40 CFR 60.331 (q)]. The requirements for electric utility stationary gas turbines are applicable to the project and are the most stringent provision of the NSPS. These requirements are summarized in Table 4-1 and were considered in the BACT analysis.

As noted from Table 4-1, the NSPS NO_x emission limit can be adjusted upward to allow for fuel-bound nitrogen (FBN). For a fuel-bound nitrogen concentration of 0.015 percent or less, no increase in the NSPS is provided.

Table 4-1. Federal NSPS for Electric Utility Stationary Gas Turbines

Pollutant	Emission Limitation[a]
Nitrogen Oxides[b]	0.0075 percent by volume (75 ppm) at 15 percent O_2 on a dry basis adjusted for heat rate and fuel nitrogen

[a] Applicable to electric utility gas turbines with a heat input at peak load of greater than 100 x 10^6 British thermal units per hour.
[b] Standard is multiplied by 14.4/Y; where Y is the manufacturer's rated heat rate in kilojoules per watt at rated load or actual measured heat rate based on the lower heating value of fuel measured at actual peak load; Y cannot be greater than 14.4. Standard is adjusted upward (additive) by the percent of nitrogen in the fuel:

Fuel-bound nitrogen (percent by weight)	Allowed Increase Nitrogen Oxide Percent By Volume
$N \leq 0.015$	0
$0.015 < N \leq 0.1$	0.04(N)
$0.1 < N \leq 0.25$	0.004+0.0067(N-0.1)
$N > 0.25$	0.005

where:

N = the nitrogen content of the fuel (percent by weight).

Source: 40 CFR 60 Subpart GG.

For the proposed CT, the NSPS emission limit would be 126 ppm corrected to 15 percent oxygen at a fuel-bound nitrogen content of 0.015 percent. The applicable NSPS for the duct burners will be 40 CFR 60, Subpart Db. The applicable requirements are presented in Table 4-2.

4.3 <u>BEST AVAILABLE CONTROL TECHNOLOGY</u>

4.3.1 CARBON MONOXIDE (CO)

4.3.1.1 <u>Emission Control Hierarchy</u>

CO emissions are a result of incomplete or partial combustion of fossil fuel. Combustion design and catalytic oxidation are the control alternatives that are viable for the project.

Combustion design is the more common control technique used in CTs. Sufficient time, temperature, and turbulence is required within the combustion zone to maximize combustion efficiency and minimize the emissions of CO. Combustion efficiency is dependent upon combustor design. When wet NO_x control systems are employed, the amount of water or steam injected in the combustion zone also affects combustion efficiency. For the CTs being evaluated and with wet injection NO_x control, CO emissions will not exceed 75 ppm, corrected to dry conditions when firing either natural gas or distillate fuel oil. These emission limits are based on calculated CO levels with margins added to account for the lack of operating experience with the LM 6000. Actual emissions under full-load conditions are expected to be less than one-half of those presented in this application.

Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use this Lowest Achievable Emission Rate (LAER) technology and typically have CO limits in the 10 ppm range (corrected to dry conditions).

Table 4-2. Federal NSPS for Industrial Steam-Generating Units, 40 CFR 60, Subpart Db[a] (Page 1 of 2)

Pollutant	Emission Limitation for Gaseous or Liquid Fuels
Particulate Matter	Natural gas - no emission limits Oil - 0.10 lb/10^6 Btu
Visible Emissions	20% opacity (6-minute average), except up to 27% opacity is allowed for one 6-minute period per hour
Sulfur Dioxide[b]	Natural gas - no emission limits Oil: 1) Annual capacity factor for oil > 30% - 0.80 lb/10^6 Btu <u>and</u> 90% reduction in potential emissions 2) Annual capacity factor for oil < 30%[c] - 0.30 lb/10^6 Btu (no percentage reduction requirements) 3) Combustion of 0.3 lb sulfur dioxide/10^6 Btu or less oil - 0.30 lb/10^6 Btu - No percentage reduction requirements
Nitrogen Oxides	Natural gas/distillate oil: 1) Low heat release rate unit - 0.10 lb/10^6 Btu 2) High heat release rate unit - 0.20 lb/10^6 Btu 3) Duct burner in combined cycle system - 0.20 lb/10^6 Btu Residual oil: 1) Low heat release rate unit - 0.30 lb/10^6 Btu 2) High heat release rate unit - 0.40 lb/10^6 Btu 3) Duct burner in combined cycle system - 0.40 lb/10^6 Btu

Table 4-2. Federal NSPS for Industrial Steam-Generating Units, 40 CFR 60, Subpart Db[a] (Page 2 of 2)

Pollutant	Emission Limitation for Gaseous or Liquid Fuels

Note:
< = less than.
> = greater than.
$lb/10^6$ Btu = pounds per million British thermal unit.
$SO_2/10^6$ Btu = sulfur dioxide per million British thermal unit.

[a] Applies to any device that combusts fuel to produce steam and that has a maximum heat input of more than 100 x 10^6 British thermal units per hour. Sources subject to Subpart Da are not subject to Subpart Db.
[b] Compliance determined on a 30-day, rolling average basis (with certain exceptions).
[c] Includes combines cycle system where 30 percent or less of the heat input to the steam generator is from combustion of oil in the duct burner and 70 percent or more of the heat input is from the gas turbine exhaust gases entering the duct burner.

Source: 40 CFR 60, Subpart Db.

4.3.1.2 Technology Description

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst, such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CTs, the oxidation catalyst can be located directly after the CT. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency. The existing oxidation catalyst applications primarily have been limited to smaller cogeneration facilities burning natural gas.

Oxidation catalysts have not been used on fuel-oil-fired CTs or combined cycle facilities. The use of sulfur-containing fuels in an oxidation catalyst system would result in an increase of SO_3 emissions and concomitant corrosive effects to the stack. In addition, trace metals in the fuel could result in catalyst poisoning during prolonged periods of operation.

Since the unit will require startups, variations in exhaust conditions will influence catalyst life and performance. Very little technical data exist to demonstrate the effect of such cycling. There is also a lack of demonstrated operation with oil firing.

Combustion design is dependent upon the manufacturer's operating specifications, which include the air-to-fuel ratio and the amount of steam injected. The CTs proposed for the project have designs to optimize combustion efficiency and minimize CO emissions. Installations with an oxidation catalyst and combustion controls generally have controlled CO levels of 10 ppm as LAER and BACT.

For the project, the following alternatives were evaluated for natural gas firing as BACT:

1. Oxidation catalyst at 10 parts per million volume, dry (ppmvd); maximum annual CO emissions are 42.6 TPY;
2. Combustion controls at 75 percent control; maximum annual CO emissions are 319.8 TPY.

4.3.1.3 Impact Analysis

Economic--The estimated annualized cost of a CO oxidation catalyst is $473,686 (Table 4-3), with a cost effectiveness of about $1,833/ton of CO removed. The cost effectiveness is based on 87 percent efficiency (75 ppmvd to 10 ppmvd). No costs are associated with combustion techniques since they are inherent in the design.

Environmental--The air quality impacts of both oxidation catalyst control and combustion design control techniques are below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst.

Energy--An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 2 inches water gauge would be expected. At a catalyst back pressure of about 2 inches, an energy penalty of about 753,360 kilowatt-hour per year (kWh/yr) would result at 100 percent load. This energy penalty is sufficient to supply the electrical needs of about 60 residential customers over a year. To replace this lost energy, about 0.75×10^{10} Btu/yr or about 7.5 million cubic feet per year (ft^3/yr) of natural gas would be required.

4.3.1.4 Proposed BACT and Rationale

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered unreasonable for the following reasons:

Table 4-3. Capital and Annualized Cost for Oxidation Catalyst (Page 1 of 2)

Cost Component	Cost ($)	Basis
I. CAPITAL COSTS		
A. DIRECT:		
1. Associated Equipment for Catalyst	75,833	Manufacture Estimate - $1,750 per lb/sec mass flow
2. Exhaust Stack Modification	75,000	Engineering Estimate - $75,000/CT
3. Installation	145,139	25% of Equipment Costs (I.A.1. & 2., and II.A.)
B. INDIRECT:		
1. Engineering & Supervision	43,542	7.5% of Equipment Costs (I.A.1. & 2., and II.A.)
2. Construction and Field Expense	58,056	10% of Equipment Costs (I.A.1. & 2., and II.A.)
3. Construction Contractor Fee	29,028	5% of Equipment Costs (I.A.1. & 2., and II.A.)
4. Startup & Testing	11,611	2% of Equipment Costs (I.A.1. & 2., and II.A.)
5. Contingency	109,552	25% of Direct and Indirect Capital Costs (I.A, and I.B.1-4)
6. Interest During Construction	146,622	15% of Direct and Indirect Capital Costs, and Recurring Capital Costs (I.A., I.B.1.-4 and II.A.)
TOTAL CAPITAL COSTS	694,383	Sum of Direct and Indirect Capital Costs
ANNUALIZED CAPITAL COSTS	81,562	Capital Recovery of 10% over 20 years
II. RECURRING CAPITAL COSTS		
A. Catalyst	429,722	Manufacture Estimate - $1,750 per lb/sec mass flow
B. Contingency	107,431	25% of Recurring Capital Costs (II.A)
TOTAL RECURRING CAPITAL COSTS	537,153	Sum of Recurring Capital Costs
ANNUALIZED RECURRING CAPITAL COSTS	215,997	Capital Recovery of 10% over 3 years
III. OPERATING & MAINTENANCE COSTS		
A. DIRECT:		
1. Labor - Operator & Supervisor	5,262	4 hours/week, 52 weeks/year, $22/hour and 15% supervisor cost
2. Maintenance	6,158	0.5% of Total and Recurring Capital Costs
3. Inventory Cost	8,413	Capital Carrying cost (10% over 20 years) for catalyst for 1 charge
B. ENERGY COSTS		
1. Heat Rate Penalty	38,582	0.2% heat reat penalty. $50/MW energy loss
2. MW Loss Penalty (Catalyst Changeout)	51,600	Loss of 43 MW for one day
3. Fuel Escalation Costs	17,539	Fuel escalation of 3% over inflation; annualized over 20 years
4. Contingency	26,930	25% of energy costs

Table 4-3. Capital and Annualized Cost for Oxidation Catalyst (Page 2 of 2)

Cost Component	Cost ($)	Basis
C. INDIRECT:		
1. Overhead	6,852	60% of Labor and Maintenance Costs (III.A.1. and 2.)
2. Property Taxes	12,315	1% of Total and Recurring Capital Cost
3. Insurance	12,315	1% of Total and Recurring Capital Cost
4. Administration	24,631	2% of Total and Recurring Capital Cost
Annualized Capital Costs	81,562	
Annualized Recurring Capital Costs	215,997	
TOTAL ANNUALIZED COSTS	508,156	Sum of Operating and Maintenance and Annualized Capital Costs

Note: All calculations using machine performance were based on operating conditions.Assumptions based on percentage of costs were adapted from EPA OAQPS Control Cost Manual (1990).

1. Catalytic oxidation will not produce measurable reduction in the air quality impacts,
2. The economic impacts are significant (i.e., an annualized cost of almost one-half million dollars, with a cost effectiveness of almost $2,000/ton of CO removed), and
3. Actual CO emissions are expected to be one-half or less than those proposed. The proposed level is based on the lack of operating experience with the LM 6000 in industrial applications.

4.3.2 OTHER REGULATED AND NONREGULATED POLLUTANT EMISSIONS

The PSD source applicability analysis shows that the PSD significant emission level is exceeded for PM10 and As, requiring PSD review (including BACT) for these pollutants. The emission of particulates from the CTs is a result of incomplete combustion and trace solids in the fuel (particularly fuel oil) and in the injected water or steam used for NO_x control. The design of the CTs ensures that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on oil- or gas-fueled CTs. The No. 2 (i.e. distillate) fuel oil to be used in the CTs will contain only trace quantities of particulate (i.e., typically about 0.05 percent ash or less in fuel oil).

The maximum particulate emissions from the CTs when burning fuel oil will be a lower concentration than that normally specified for fabric filter designs; i.e., the grain loading associated with the maximum particulate emissions [about 15 pounds per hour (lb/hr)] is less than 0.01 grains per standard cubic foot (gr/scf), which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the proposed project.

Therefore, there are no technically feasible methods for controlling the emissions of these pollutants from CTs, other than the inherent quality of the fuel. Levels of trace metals in distillate oil are limited by fuel oil specifications. Natural gas and distillate oil represents BACT for this pollutant.

For the nonregulated pollutants, most of which are trace metals, none of the control technologies evaluated for other pollutants (i.e., oxidation catalyst) would reduce such emissions; thus, natural gas and low sulfur distillate oil represent BACT because of their inherent low metals content.

5.0 AIR QUALITY MONITORING DATA

5.1 PSD PRECONSTRUCTION

The CAA requires that an air quality analysis be conducted for each pollutant subject to regulation under the act before a major stationary source or major modification is constructed. This analysis may be performed by the use of modeling and/or by monitoring the air quality. The use of monitoring data refers to either the use of representative air quality data from existing monitoring stations or establishing a monitoring network to monitor existing air quality. Monitoring must be conducted for a period up to 1 year prior to submission of a construction permit application. In addition to establishing existing air quality, the air quality data are useful for determining background concentrations (i.e., concentrations from sources not considered in the modeling). The background concentrations can be added to the concentrations predicted for the sources considered in the modeling to estimate total air quality impacts. These total concentrations are then evaluated to determine compliance with the AAQS.

For the criteria pollutants, continuous air quality monitoring data must be used to establish existing air quality concentrations in the vicinity of the proposed source or modification. However, preconstruction monitoring data generally will not be required if the ambient air quality concentration before construction is less than the de minimis impact monitoring concentrations (refer to Table 3-2 for de minimis impact levels). Also, if the maximum predicted impact of the source or modification is less than the de minimis impact monitoring concentrations, the source generally would be exempt from preconstruction monitoring.

For noncriteria pollutants, EPA recommends that an analysis based on air quality modeling generally should be used instead of monitoring data. The permit-granting authority has discretion in requiring preconstruction monitoring data when:

1. The state has an air quality standard for the noncriteria pollutant, and emissions from the source or modification pose a threat to the standard;
2. The reliability of emission data used as input to modeling existing sources is highly questionable; or
3. Air quality models have not been validated or may be suspect for certain situations, such as complex terrain or building downwash conditions.

However, if the maximum concentrations from the major source or major modification are predicted to be above the significant monitoring concentrations, EPA recommends that an EPA-approved measurement method be available before a permit-granting authority requires preconstruction monitoring.

EPA's Ambient Monitoring Guidelines for PSD (EPA, 1987a) sets forth guidelines for preconstruction monitoring. The guidelines allow the use of existing air quality data in lieu of additional air monitoring if the existing data are representative. The criteria used in determining the representativeness of data are monitor location, quality of data, and currentness of data.

For the first criterion, monitor location, the existing monitoring data should be representative of three types of areas:

1. The location(s) of maximum concentration increase from the proposed source or modification;
2. The location(s) of the maximum air pollutant concentration from existing sources; and
3. The location(s) of the maximum impact area (i.e., where the maximum pollutant concentration hypothetically would occur, based on the combined effect of existing sources and the proposed new source or modification).

Basically, the locations and size of the three types of areas are determined through the application of air quality models. The areas of maximum concentration or maximum combined impact vary in size and are influenced by factors such as the size and relative distribution of ground level and elevated sources, the averaging times of concern, and the distances between impact areas and contributing sources.

For the second criteria, data quality, the monitoring data should be of similar quality as would be obtained if the applicant were monitoring according to PSD requirements. As a minimum, this would mean:

1. Use of continuous instrumentation,
2. Production of quality control records that indicate the instruments' operations and performances,
3. Operation of the instruments to satisfy quality assurance requirements, and
4. Data recovery of at least 80 percent of the data possible during the monitoring effort.

For the third criteria, currentness of data, the monitoring data must have been collected within a 3-year period preceding the submittal of permit application and must still be representative of current conditions.

5.2 PROJECT MONITORING APPLICABILITY

As determined by the source applicability analysis described in Section 3.4, an ambient monitoring analysis is required by PSD regulations for PM10, CO, and As emissions. As may be exempt from monitoring requirements because no acceptable monitoring technique has been established for that pollutant. The maximum predicted impacts from the proposed turbines also are less than de minimis levels for PM10 and CO. Therefore, preconstruction monitoring is not required for those pollutants for this project.

6.0 AIR QUALITY MODELING APPROACH

6.1 ANALYSIS APPROACH AND ASSUMPTIONS

6.1.1 GENERAL MODELING APPROACH

The general modeling approach follows EPA and FDER modeling guidelines. The highest predicted concentrations are compared with both PSD significant impact levels and *de minimis* air quality levels. If a facility exceeds the significant impact level for a particulate pollutant, current policies stipulate that the highest annual average and HSH short-term (i.e., 24 hours or less) concentrations be compared with AAQS and PSD increments when 5 years of meteorological data are used. The HSH concentration is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

This approach is consistent with the air quality standards, which permit a short-term average concentration to be exceeded once per year at each receptor.

To develop the maximum short-term concentrations for the facility, the general modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. The basic difference between the two phases is the receptor grid used when predicting concentrations.

Concentrations for the screening phase were predicted using a coarse receptor grid and a 5-year meteorological record. After a final list of maximum short-term concentrations was developed, the refined phase of the analysis was conducted by predicting concentrations for a refined receptor grid centered on the receptor at which the HSH concentration from the screening phase was produced. The air dispersion model then was executed for the entire year during which HSH concentrations were predicted. This approach was used to ensure that valid HSH concentrations were obtained. More detailed descriptions of the emission inventory and receptor grids used in the screening and refined phases of the analysis are presented in the following sections.

6.1.2 MODEL SELECTION

The selection of the appropriate air dispersion model was based on its ability to simulate impacts in areas surrounding the plant site. Within 50 km of the site, the terrain can be described as mostly simple (i.e., flat to gently rolling). As defined in the EPA modeling guidelines, simple terrain is considered to be an area where the terrain features are all lower in elevation than the top of the stack(s) under evaluation. There are some areas with 5 km from the stack where the terrain rises up to 10 ft above the effective stack height. This terrain would be considered marginally intermediate terrain. However, because the terrain rises no higher than this height, which is well below the stable plume elevation (approximately 380 ft) a simple terrain model was selected to predict maximum ground-level concentrations.

The Industrial Source Complex (ISC) dispersion model (EPA, 1988a) was selected to evaluate the pollutant emissions from the proposed unit and other modeled sources. This model is contained in EPA's User's Network for Applied Modeling of Air Pollution (UNAMAP), Version 6 (EPA, 1988b). The ISC model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights.

The ISC model consists of two sets of computer codes that are used to calculate short- and long-term ground level concentrations. The main differences between the two codes are the input format of the meteorological data and the method of estimating the plume's horizontal dispersion.

The first model code, the ISC short-term (ISCST) model, is an extended version of the single-source (CRSTER) model (EPA, 1977). The ISCST model is designed to calculate hourly concentrations based on hourly meteorological parameters (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The hourly concentrations are processed into non-overlapping, short-term, and annual averaging periods. For example, a 24-hour average concentration is based on twenty-four 1-hour averages calculated from midnight to midnight of each day. For each short-term averaging period selected, the highest and second-highest average concentrations are calculated for each receptor. As an option, a table of the 50 highest concentrations over the entire field of receptors can be produced.

The second model code within the ISC model is the ISC long-term (ISCLT) model. The ISCLT model uses joint frequencies of wind direction, wind speed, and atmospheric stability to calculate seasonal and/or annual average ground-level concentrations. Because the input wind directions are for 16 sectors, with each sector defined as 22.5 degrees, the model calculates concentrations by assuming that the pollutant is uniformly distributed in the horizontal plane within a 22.5-degree sector.

In this analysis, the ISCST model was used to calculate both short-term and annual average concentrations because these concentrations are readily obtainable from the model output. Major features of the ISCST model are presented in Table 6-1. Concentrations caused by stack and volume sources are calculated by the ISCST model using the steady-state Gaussian plume equation for a continuous source. The area source equation in the ISCST model is based on the equation for a continuous and finite crosswind line source. The ISC model has rural and urban options that affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground-level concentrations. The criteria used to determine when the rural or urban mode is appropriate are based on land use near the proposed plant's surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50 percent of the area

Table 6-1. Major Features of the ISCST Model

ISCST Model Features
• Polar or Cartesian coordinate systems for receptor locations
• Rural or one of three urban options that affect wind speed profile exponent, dispersion rates, and mixing height calculations
• Plume rise as a result of momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975)
• Procedures suggested by Huber and Snyder (1976); Huber (1977); Schulmann and Hanna (1986); and Schulmann and Scire (1980) for evaluating building wake effects
• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
• Separation of multiple-point sources
• Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
• Capability of simulating point, line, volume, and area sources
• Capability to calculate dry deposition
• Variation with height of wind speed (wind speed-profile exponent law)
• Concentration estimates for 1-hour to annual average
• Terrain-adjustment procedures for elevated terrain, including a terrain truncation algorithm
• Receptors located above local terrain (i.e., "flagpole" receptors)
• Consideration of time-dependent exponential decay of pollutants
• The method of Pasquill (1976) to account for buoyancy-induced dispersion
• A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
• Procedure for calm-wind processing
• Wind speeds less than 1 m/s are set to 1 m/s.

Source: EPA, 1990.

within a 3-km radius circle centered on the proposed source, the urban option should be selected. Otherwise, the rural option is more appropriate.

For modeling analyses that will undergo regulatory review, such as PSD permit applications, the following model features are recommended by EPA (1987a) and are referred to as the regulatory options in the ISCST model:

1. Final plume rise at all receptor locations,
2. Stack-tip downwash,
3. Buoyancy-induced dispersion,
4. Default wind speed profile coefficients for rural or urban option,
5. Default vertical potential temperature gradients,
6. Calm wind processing, and
7. Reducing calculated SO_2 concentrations in urban areas by using a decay half-life of 4 hours (i.e., reduce the SO_2 concentration emitted by 50 percent for every 4 hours of plume travel time).

In this analysis, the EPA regulatory options were used to address maximum impacts. Based on a review of the land use around the facility and discussions with FDER, the rural mode was selected because of the lack of residential, industrial, and commercial development within 3 km of the plant site.

6.2 METEOROLOGICAL DATA

Meteorological data used in the ISCST model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Jacksonville International Airport and Waycross, Georgia, respectively. The 5-year period of meteorological data was from 1983 through 1987. The NWS station in Jacksonville is the nearest weather station which routinely records the hourly surface data required by the air dispersion models. The station is more than 20 miles inland from the Atlantic Ocean and, similar to Alachua County, is not significantly

$$M_w = \frac{\pi W^2}{4}$$

$$M_w = 0.8886\ W$$

where: M_w is input to the model to produce a building width of W used in the dispersion calculation. W is the actual building width.

The building structures considered in the modeling analysis are presented in Table 6-2. A site location map showing the location of these structures is presented in Figure 6-1.

Building dimensions for the proposed cogeneration plant and the existing heat plant were supplied by FPC and Energy Services, Inc. The dimensions of UF structures in the vicinity of the proposed plant site were obtained from maps made available by the Physical Plant Division at UF. Information on the J. Hillis Miller Health Center buildings was obtained from a map from the Department of General Services at UF.

All buildings that are closer than five times their height or maximum width (whichever is less) are considered to be within the zone of influence of the proposed facility and must then be incorporated in the modeling.

The following buildings at UF were analyzed and found to be outside the zone of influence of the proposed cogeneration facility:

1. The Health Science Center-Dentistry Department,
2. The Health Science Center-Veterinary Medicine Department,
3. Black Hall,
4. East and West Parking Garages to southeast of plant,
5. The existing UF Heat Plant No. 2, and
6. The proposed Ambulatory Center.

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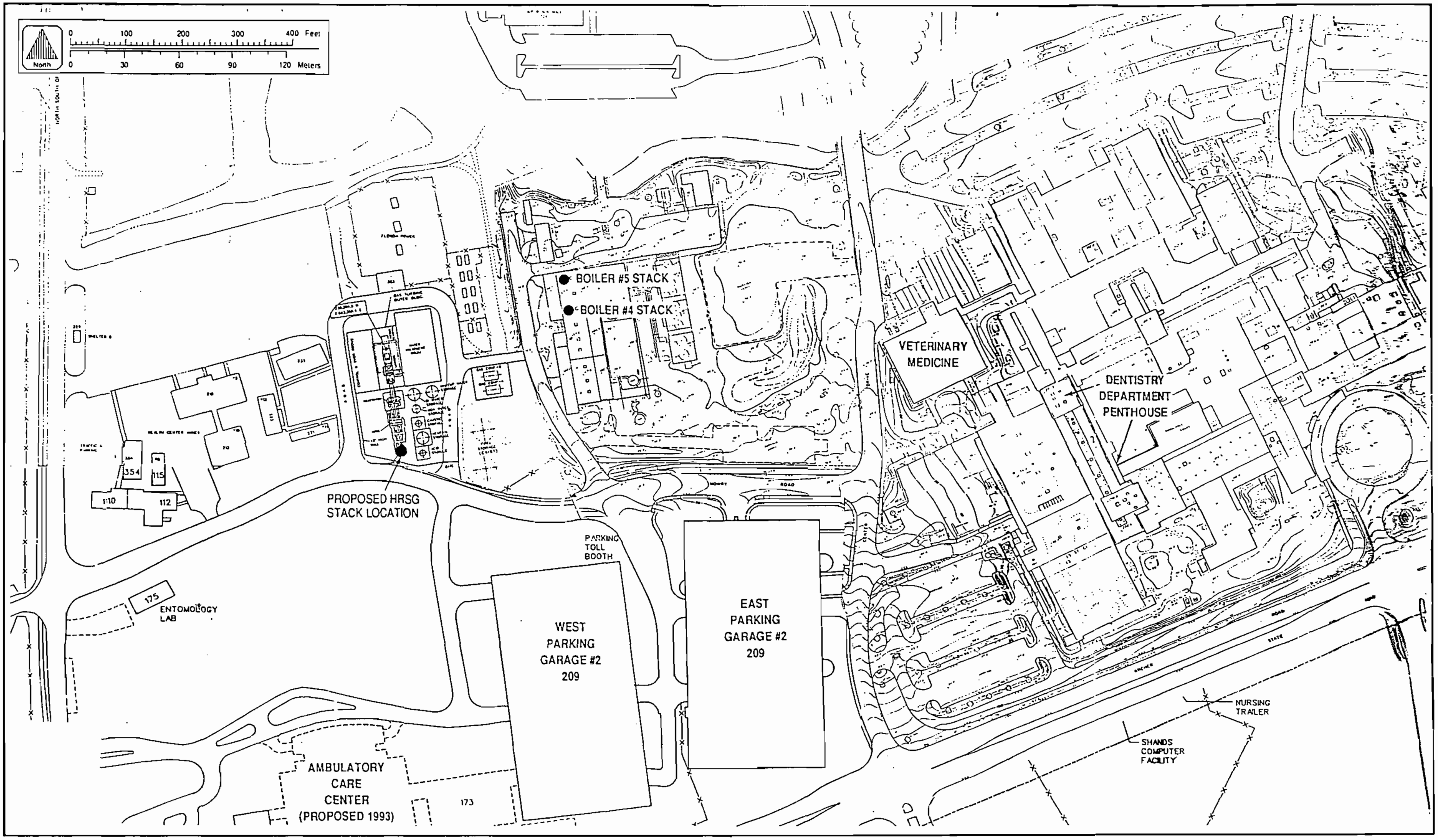

Figure 6-1 SITE AREA MAP INDICATING ALL BUILDING STRUCTURES CONSIDERED IN THE MODELING ANALYSIS

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The proposed HRSG building is the dominant structure for the HRSG stack that was within the zone of influence. The dimensions of the HRSG are 57 ft high and 54 by 14 ft horizontally. The maximum projected width (MPW x 0.886) is 49.4 ft. Direction-specific building directions were not required for modeling this source.

Table 6-2. Building Structures Considered in the Modeling Analysis

Structure	Height[a] (ft)	Diagonal (ft)	Distance to Stacks (ft) HRSG	Units 4 and 5
HRSG Boiler Building	57	55.8	0	300[b]
UF Heating Plant Building	41.6	257	300[b]	0
UF Health Center				
Dentistry Department	143	270	1080[b]	820[b]
(Penthouse)				
Veterinary Medicine Building	59	180	845[b]	550[b]
West Parking Garage	65	480	340[b]	440[b]
East Parking Garage	65	480	510[b]	420[b]
Ambulatory Care Center				
(Proposed 1993)				
8th floor level	80[c]	143	580[b]	860[b]
9th floor level	90[c]	89	580[b]	860[b]
10th floor level	100[c]	66	580[b]	860[b]
University of Florida				
Black Hall	63	145	720[b]	440[b]

Note: ft = feet.
HRSG = heat recovery steam generators.
UF = University of Florida.

[a]Above mean grade level.
[b]Stack is beyond the downwash zone of influence of this structure.
[c]Estimate.

7.0 AIR QUALITY MODELING RESULTS

7.1 SIGNIFICANT IMPACT ANALYSIS

A summary of the maximum concentrations as a result of the proposed turbine operating at maximum load conditions is presented in Table 7-1. Table 7-1 indicates the maximum screening concentrations for each year and averaging time with an emission rate of 10 g/s. Based on the results in Table 7-1, refined modeling was performed. The results of the refined modeling are presented in Table 7-2, including receptor location and the day and period of the maximum impacts. The maximum pollutant-specific concentrations for PM and CO were determined from the maximum generic impacts and are presented in Table 7-3.

The maximum predicted 1-hour and 8-hour CO concentrations are 250.0 and 58.7 $\mu g/m^3$, respectively. Because these concentrations are below the PSD significant levels of 2,000 and 500 $\mu g/m^3$, additional modeling is not necessary for CO.

The maximum predicted annual and 24-hour average PM10 concentrations when firing oil only are 0.12 and 4.63 $\mu g/m^3$, respectively. With the primary fuel, natural gas, the maximum impacts are 0.06 and 2.22 $\mu g/m^3$ for the annual and 24-hour averaging times, respectively. These maximum impacts are less than the PM10 significance impact levels. Therefore, additional modeling is not required for this pollutant.

7.2 TOXIC POLLUTANT ANALYSIS

The maximum impacts of regulated and nonregulated hazardous pollutants that will be emitted in significant amounts by the proposed facility (see Table 3-3) are presented in Table 7-4. Inorganic arsenic is the only pollutant to be addressed and is compared in the table to the FDER No Threat Levels (NTL). The maximum 8-hour, 24-hour, and annual impacts for arsenic are well below the NTL for each respective averaging time.

Table 7-1. Maximum Predicted Impacts for the UF Cogeneration Facility Using a Generic Emission Rate of 10 Grams Per Second--Screening Analysis (Page 1 of 2)

Averaging Time	Year	Concentration (μg/m3)	Receptor Location[a] Direction (degrees)	Distance (m)	Day/ Period
Annual					
	1983	0.85	220	70	- / -
	1984	0.53	220	70	- / -
	1985	0.72	230	70	- / -
	1986	0.54	230	70	- / -
	1987	0.99	120	70	- / -
1-Hour[b]					
	1983	135.31	40	100	92/16
	1984	110.53	80	70	244/23
	1985	162.96	130	70	45/23
	1986	131.36	120	70	27/12
	1987	99.60	120	70	23/ 2
3-Hour[b]					
	1983	73.04	220	70	44/ 5
	1984	83.44	60	70	88/ 6
	1985	62.31	110	70	359/ 4
	1986	57.87	230	70	81/ 5
	1987	54.57	120	70	363/ 1
8-Hour[b]					
	1983	44.86	220	70	44/ 2
	1984	42.19	60	70	88/ 3
	1985	40.49	100	70	43/ 1
	1986	42.44	120	70	27/ 2
	1987	39.46	110	70	338/ 2

Table 7-1. Maximum Predicted Impacts for the UF Cogeneration Facility Using a Generic Emission Rate of 10 Grams Per Second--Screening Analysis (Page 2 of 2)

Averaging Time	Year	Concentration (μg/m3)	Receptor Location[a] Direction (degrees)	Distance (m)	Day/ Period
24-Hour[b]					
	1983	36.07	220	70	44/ 1
	1984	27.95	60	70	88/ 1
	1985	28.49	100	70	43/ 1
	1986	21.88	120	70	27/ 1
	1987	19.78	130	70	11/ 1

Note: $\mu g/m^3$ = micrograms per cubic meter
m = meter

[a] Relative to the location of the proposed unit.
[b] All short-term concentrations indicate highest, second-highest concentrations.

Table 7-2. Maximum Predicted Impacts for the UF Cogeneration Facility Using a Generic Emission Rate of 10 Grams Per Second--Refined Analysis

Averaging Time	Year	Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (degrees)	Receptor Location[a] Distance (m)	Day/ Period
Annual					
	1987	0.99	122	70	
1-Hour[b]					
	1985	203.3	128	70	45/23
3-Hour[b]					
	1984	83.44	60	70	88/6
8-Hour[b]					
	1983	47.75	218	70	44/2
	1984	47.59	56	70	88/2
	1986	44.60	118	70	27/2
24-Hour[b]					
	1983	36.71	218	70	44/1

Note: $\mu g/m^3$ = micrograms per cubic meter
m = meter

[a]Relative to the location of the proposed unit.
[b]All short-term concentrations indicate highest predicted concentrations.

Table 7-3. Maximum Predicted Pollutant Impacts of the UF Cogeneration Facility Compared to PSD Significant Impact Levels

Pollutant	Averaging Period	Emission Rate (lb/hr)	Generic Impact ($\mu g/m^3$)	Predicted Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)
Particulate	Annual	10[a]	0.99	0.12 (0.06)	1
Matter (PM10)	24-Hour	(4.8)[b]	36.7	4.63 (2.22)	5
Carbon	1-Hour	70.5[a]	203.3	180.6 (250.0)	2,000
Monoxide	8-Hour	(97.6)[b]	47.75	42.4 (58.7)	500

Note: Short-term maximum impacts are highest predicted concentrations for 1983-87.

lb/hr = pounds per hour
$\mu g/m^3$ = micrograms per cubic meter

[a] Emission rate for firing oil, which will be used up to 438 hours per year and only during natural gas curtailments.

[b] Emission rate for the turbine and duct burner firing natural gas, the primary fuel. Impacts for natural gas shown in parentheses.

Table 7-4. Predicted Maximum Impacts of Toxic Pollutants for the UF Cogeneration Facility

Pollutant	Averaging Period	Emission Rate (lb/hr)	Generic Impact ($\mu g/m^3$)	Predicted Impact ($\mu g/m^3$)	No Threat Levels ($\mu g/m^3$)
Non-Regulated					
Inorganic Arsenic	8-Hour	1.5×10^{-4} [a]	47.75	0.00009	0.50
	24-Hour		36.7	0.00007	0.48
	Annual		0.99	0.000002	2.3×10^{-4}

Note: Short-term generic impacts are highest predicted concentrations for 1983-1987.

lb/hr = pounds per hour
$\mu g/m^3$ = micrograms per cubic meter

[a]Based on total TPY.

7.3 ADDITIONAL IMPACT ANALYSIS

7.3.1 IMPACTS UPON SOILS AND VEGETATION

Predicted impacts of all regulated pollutants are less than the significant impact levels (see Table 7-3). As a result, no impacts are expected to occur to soils or vegetation as a result of the proposed emissions of other regulated pollutants.

7.3.2 IMPACTS DUE TO ADDITIONAL GROWTH

A limited number of additional personnel may be added to the current plant personnel. These additional personnel are expected to have an insignificant effect on the residential, commercial, and industrial growth in UF.

7.3.3 IMPACTS TO VISIBILITY

The plant is located approximately 125 km from the Chassahowitzka Wilderness Area, a PSD Class I area. Impacts to visibility were estimated using the VISCREEN computer model. Impacts were calculated for particulates and nitrogen oxides (as nitrogen dioxide). The results of the screening analysis are presented in Table 7-5. Based on the results, the proposed facility is not expected to significantly impair visibility in the Chassahowitzka Wilderness Area.

Table 7-5. Visibility Analysis for the UF Cogeneration Facility

Visual Effects Screening Analysis for
Source: UF COGENERATION FACILITY
Class I Area: CHASSAHOWITZKA WILDERNESS
*** Level-1 Screening ***

Input Emissions for

Particulates	17.00	TON/YR
NOx (as NO2)	38.80	TON/YR
Primary NO2	.00	TON/YR
Soot	.00	TON/YR
Primary SO4	.00	TON/YR

**** Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	25.00 km
Source-Observer Distance:	125.00 km
Min. Source-Class I Distance:	125.00 km
Max. Source-Class I Distance:	135.00 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.	125.0	84.	2.00	.001	.05	.000
SKY	140.	84.	125.0	84.	2.00	.000	.05	.000
TERRAIN	10.	85.	125.3	84.	2.00	.000	.05	.000
TERRAIN	140.	85.	125.3	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.	121.0	94.	2.00	.001	.05	.000
SKY	140.	75.	121.0	94.	2.00	.000	.05	.000
TERRAIN	10.	55.	111.9	114.	2.00	.000	.05	.000
TERRAIN	140.	55.	111.9	114.	2.00	.000	.05	.000

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APPENDIX A

Table A-1. Design Information and Stack Parameters for University of Florida Cogeneration Project

Data A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine Fuel Oil D
General:			
Power (kW)	43,262.0	NA	43,098.0
Heat Rate (Btu/kwh)	8,043.0 η=42.5%	NA	8,877.0
Heat Input (mmBtu/hr)	348.0	187.0 ~50% of heat input	382.6
Fuel Oil (lb/hr)	18,313.5	9,842.1	20,792.4
(cf/hr)	367,818.5	197,674.4	
Fuel:			
Heat Content - (LHV)	19,000 Btu/lb	19,000 Btu/lb	18,400 Btu/lb
Sulfur	1 gr/100cf	1 gr/100cf	0.5
CT Exhaust:			
Volume Flow (acfm)	564,678		569,684
Volume Flow (scfm)	239,478		235,916
Mass Flow (lb/hr)	1,036,522		1,030,290
Temperature (°F)	785		815
Moisture (% Vol.)	11.25		8.54
Oxygen (% Vol.)	13.73		13.60
Molecular Weight	27.80		28.05
Steam Injected (lb/hr)	31,402		22,504
HRSG Stack:			
Volume Flow (acfm)	325,200		320,364
Temperature (°F)	257		257
Diameter (ft)	9.75		9.78
Velocity (ft/sec)	72.59		71.51

Source: General Electric and Stewart and Stevenson, 1991.

Note: All data shown on this table and subsequent tables are for the combustion turbine and duct burner.

Table A-2. Maximum Criteria Pollutant Emissions for Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine Fuel Oil D
<u>Particulate:</u>			
Basis	Manufacturer	0.01 lb/mmBtu	Manufacturer
lb/hr	2.50	1.87	10.0
TPY	10.95	7.37	2.2
<u>Sulfur Dioxide:</u>			
Basis	1 gr/100 cf	1 gr/100 cf	0.5 % Sulfur
lb/hr	1.05	0.56	197.53
TPY	4.60	2.23	43.3
<u>Nitrogen Oxides:</u>			
Basis	25 ppm*	0.1 lb/mmBtu	42 ppm*
lb/hr	35.0	18.7	66.3
TPY	~~153.4~~	73.72	14.5
ppm	25.0	NA	42.0
<u>Carbon Monoxide:</u>			
Basis	75 ppm+	0.15 lb/mmBtu	75 ppm+
lb/hr	69.5	28.1	70.5
TPY	304.37	110.57	15.4
ppm	75.0	NA	75.0
<u>VOC's:</u>			
Basis	4 ppm+	0.043 lb/mmBtu	10 ppm+
lb/hr	1.59	8.04	4.03
TPY	7.0	31.70	0.9
ppm	4.0	NA	10.0
<u>Lead:</u>			
Basis			EPA(1988)
lb/hr	NA	NA	3.40E-03
TPY	NA	NA	7.46E-04

[a]Corrected to 15% O_2 dry conditions.
[b]Corrected to dry conditions.

Note: Annual emission for CT when firning natural gas based on 8,760 hrs/yr and 415 hrs/yr for fuel oil firing. Annual emissions for duct burners on 7,884 hrs/yr (90% capacity factor).

Table A-3. Maximum Other Regulated Pollutant Emissions for UF Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine No.2 Oil D
As (lb/hr)	NEG.	NEG.	0.00160684
(TPY)	NEG.	NEG.	3.52E-04
Be (lb/hr)	NEG.	NEG.	0.0009564524
(TPY)	NEG.	NEG.	2.09E-04
Hg (lb/hr)	NEG.	NEG.	1.15E-03
(TPY)	NEG.	NEG.	2.51E-04
F (lb/hr)	NEG.	NEG.	0.0124338807
(TPY)	NEG.	NEG.	2.72E-03
H2SO4 (lb/hr)	8.04E-03	4.32E-03	1.59E+01
(TPY)	3.52E-02	0.02	3.48E+00

Sources: EPA, 1988; EPA, 1980.

Table A-4. Maximum Non-Regulated Pollutant Emissions for UF Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine No.2 Oil D
Manganese (lb/hr)	NEG.	NEG.	2.46E-03
(TPY)	NEG.	NEG.	5.40E-04
Nickel (lb/hr)	NEG.	NEG.	6.50E-02
(TPY)	NEG.	NEG.	1.42E-02
Cadmium (lb/hr)	NEG.	NEG.	4.02E-03
(TPY)	NEG.	NEG.	8.80E-04
Chromium (lb/hr)	NEG.	NEG.	1.82E-02
(TPY)	NEG.	NEG.	3.98E-03
Copper (lb/hr)	NEG.	NEG.	1.07E-01
(TPY)	NEG.	NEG.	2.35E-02
Vanadium (lb/hr)	NEG.	NEG.	2.67E-02
(TPY)	NEG.	NEG.	5.84E-03
Selenium (lb/hr)	NEG.	NEG.	8.98E-03
(TPY)	NEG.	NEG.	1.97E-03
POM (lb/hr)	3.88E-04	2.09E-04	1.07E-04
(TPY)	1.70E-03	8.22E-04	2.34E-05
Formaldehyde (lb/hr)	3.07E-02	7.57E-02	1.55E-01
(TPY)	1.35E-01	2.99E-01	3.39E-02

Table A-5. Maximum Emissions for Additional Non-Regulated Pollutant for UF Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine No.2 Oil D
Antimony (lb/hr)	NEG.	NEG.	8.36E-03
(TPY)	NEG.	NEG.	1.83E-03
Barium (lb/hr)	NEG.	NEG.	7.47E-03
(TPY)	NEG.	NEG.	1.64E-03
Colbalt (lb/hr)	NEG.	NEG.	3.47E-03
(TPY)	NEG.	NEG.	7.59E-04
Zinc (lb/hr)	NEG.	NEG.	2.61E-01
(TPY)	NEG.	NEG.	5.72E-02
Chlorine[a] (lb/hr)	NEG.	NEG.	1.04E-02
(TPY)	NEG.	NEG.	2.28E-03

Source: EPA, 1979

[a]Assumes 0.5 ppm in fuel oil.

EMISSION FACTORS AND CALCULATIONS

Emission factors used in the calculations were obtained from the following sources (references attached):

1. Compilation of air pollutant emiission factors (AP-42) for PM, SO_2, NO_x, CO, and VOC.
2. Estimating air toxics from coal and oil combustion sources (EPA, 1989) for As, Be, Pb, and Hg.
3. Emissions Assessment of Conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources (EPA, 1981) for F.

The conversions from $lb/10^{-12}$ Btu to $lb/10^3$ gal were calculated as follows:

Residual Oil = EF $lb/10^{12}$ Btu * 18,300 Btu/lb oil * 8.2 lb oil/gal

* $1{,}000/10^3$ = 1.5×10^{-4} * EF $lb/10^3$ gal

where: EF = emission factor

Distillate Oil = EF $lb/10^{12}$ Btu * 20,996/lb oil * 7.2 lb/gal

* $1{,}000/10^3$ = 1.512×10^{-4} * EF $lb/10^3$ gal

The conversion from pg/J to $lb/10^{12}$ Btu is as follows:

pg/J * 10^{-12} g/pg * lb/454 grams * 1,055 J/Btu = 2.324 $lb/10^{12}$ Btu

A

Volume is calculated based on ideal gas law:

PV = mRT/M
V = mRT/(MP) for natural gas

where:
P = pressure = 2116.8 lb/ft^2
m = mass flow of gas (lb/hr)
R = universal gas constant = 1545 ft-lb/lb-mole °R
M = molecular weight of gas
T = temperature (K)

B

NO_x is calculated by correcting to 15% O_2 dry conditions using ideal gas law and moisture and O_2 conditions.

Oxygen correction:

$$V_{NOx\ (15\%)} = \frac{V_{NOx\ Dry} * 5.9}{20.9 - \%O_{2\ Dry}}$$

$$V_{NOx\ Dry} = V_{NOx\ (15\%)}\ (20.9 - \%O_{2\ Dry})\ /\ 5.9$$

$$\%O_{2\ Dry} = \%O_{2\ Act}\ /\ (1 - \%H_2O)\ ;\ \%O_{2\ Act} = \%O_{2\ Dry}\ (1 - \%H_2O)$$

$$V_{NOx\ Act} = V_{NOx\ Dry}\ (1 - \%H_2O)$$

Substituting:

$$V_{NOx\ Act} = V_{NOx\ 15\%}\ (20.9 - \%O_{2\ Dry})\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9 - (\%O_{2\ Act}\ /\ (1 - \%H_2O))]\ (1 - \%H_2O)\ /\ 5.9$$

$$= V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2)\ /\ 5.9$$

$$m_{NOx} = \frac{PVM_{NOx}}{RT} = V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2) * P * M_{NOx}\ /\ (RT * 5.9)$$

C

CO and VOC are calculated by correcting for moisture using ideal gas law. Same as NO_x calculation except only moisture correction is used:

$$V_{CO\ Act} = V_{CO\ Dry}\ (1 - \%H_2O)$$

$$m_{CO} = PV_{CO\ Act}M_{CO}\ /\ RT$$
$$= PV_{CO\ Dry}\ (1 - \%H_2O)\ M_{CO}\ /\ RT$$

pg/J = picograms per joule

AP-42
SUPPLEMENT C
SEPTEMBER 1990

SUPPLEMENT C

TO

COMPILATION OF AIR POLLUTANT EMISSION FACTORS

VOLUME I: STATIONARY POINT AND AREA SOURCES

TABLE 1.4-1. UNCONTROLLED EMISSION FACTORS FOR NATURAL GAS COMBUSTION[a]

Furnace size & type (10^6 Btu/hr heat input)	Particulate[b]		Sulfur dioxide[c]		Nitrogen oxides[d]		Carbon monoxide[e]		Volatile organics			
									Nonmethane		Methane	
	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$	$kg/10^6 m^3$	$lb/10^6 ft^3$
Utility boilers (> 100)	16 - 80	1 - 5	9.6	0.6	8800[h]	550[h]	640	40	23	1.4	4.8	0.3
Industrial boilers (10 - 100)	16 - 80	1 - 5	9.6	0.6	2240	140	560	35	44	2.8	48	3
Domestic and commercial boilers (< 10)	16 - 80	1 - 5	9.6	0.6	1600	100	320	20	84	5.3	43	2.7

[a]Expressed as weight/volume fuel fired.
[b]References 15-18.
[c]Reference 4. Based on avg. sulfur content of natural gas, 4600 g/10^6 Nm^3 (2000 gr/10^6 scf).
[d]References 4-5, 7-8, 11, 14, 18-19, 21.
[e]Expressed as NO_2. Tests indicate about 95 weight % NO_x is NO_2.
[f]References 4, 7-8, 16, 18, 22-25.
[g]References 16, 18. May increase 10 - 100 times with improper operation or maintenance.
[h]For tangentially fired units, use 4400 kg/10^6 m^3 (275 lb/10^6 ft^3). At reduced loads, multiply factor by load reduction coefficient in Figure 1.4-1. For potential NO_x reductions by combustion modification, see text. Note that NO_x reduction from these modifications will also occur at reduced load conditions.

~ Rough Ave reduction

Retired units: $140 \frac{Lb_{NOx}}{10^6 Ft^3_{GAS}} \times \underset{\sim Ave}{100,000} \frac{Ft^3}{hr} \times \underset{\sim Ave}{3,000} \frac{hr}{yr} \times \frac{Ton_{NOx}}{2000\ Lb_{NOx}} = 21\ TPY$

TABLE 1.3-1. UNCONTROLLED EMISSION FACTORS FOR FUEL OIL COMBUSTION

EMISSION FACTOR RATING: A

Boiler Type[a]	Particulate Matter[b]		Sulfur Dioxide[c]		Sulfur Trioxide		Carbon Monoxide[d]		Nitrogen Oxide[e]		Volatile Organics[f] Nonmethane		Volatile Organics[f] Methane	
	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$	$kg/10^3 l$	$lb/10^3 gal$
Utility Boilers														
Residual Oil	g	g	19S	157S	0.34S[h]	2.9S[h]	0.6	5	8.0 (12.6)(5)[i]	67 (105)(42)[i]	0.09	0.76	0.03	0.28
Industrial Boilers														
Residual Oil	g	g	19S	157S	0.24S	2S	0.6	5	6.6[j]	55[j]	0.034	0.28	0.12	1.0
Distillate Oil	0.24	2	17S	142S	0.24S	2S	0.6	5	2.4	20	0.024	0.2	0.006	0.052
Commercial Boilers														
Residual Oil	g	g	19S	157S	0.24S	2S	0.6	5	6.6	55	0.14	1.13	0.057	0.475
Distillate Oil	0.24	2	17S	142S	0.24S	2S	0.6	5	2.4	20	0.04	0.34	0.026	0.216
Residential Furnaces														
Distillate Oil	0.3	2.5	17S	142S	0.24S	2S	0.6	5	2.2	18	0.085	0.713	0.214	1.78

[a] Boilers can be approximately classified according to their gross (higher) heat rate as shown below:
- Utility (power plant) boilers: $>106 \times 10^9$ J/hr ($>100 \times 10^6$ Btu/hr)
- Industrial boilers: 10.6×10^9 to 106×10^9 J/hr (10×10^6 to 100×10^6 Btu/hr)
- Commercial boilers: 0.5×10^9 to 10.6×10^9 J/hr (0.5×10^6 to 10×10^6 Btu/hr)
- Residential furnaces: $<0.5 \times 10^9$ J/hr ($<0.5 \times 10^6$ Btu/hr)

[b] References 3-7 and 24-25. Particulate matter is defined in this section as that material collected by EPA Method 5 (front half catch).

[c] References 1-5. S indicates that the weight % of sulfur in the oil should be multiplied by the value given.

[d] References 3-5 and 8-10. Carbon monoxide emissions may increase by factors of 10 to 100 if the unit is improperly operated or not well maintained.

[e] Expressed as NO_2. References 1-5, 8-11, 17 and 26. Test results indicate that at least 95% by weight of NO_x is NO for all boiler types except residential furnaces, where about 75% is NO.

[f] References 18-21. Volatile organic compound emissions are generally negligible unless boiler is improperly operated or not well maintained, in which case emissions may increase by several orders of magnitude.

[g] Particulate emission factors for residual oil combustion are, on average, a function of fuel oil grade and sulfur content:
- Grade 6 oil: $1.25(S) + 0.38$ kg/10^3 liter [$10(S) + 3$ lb/10^3 gal] where S is the weight % of sulfur in the oil. This relationship is based on 81 individual tests and has a correlation coefficient of 0.65.
- Grade 5 oil: 1.25 kg/10^3 liter (10 lb/10^3 gal)
- Grade 4 oil: 0.88 kg/10^3 liter (7 lb/10^3 gal)

[h] Reference 25.

[i] Use 5 kg/10^3 liters (42 lb/10^3 gal) for tangentially fired boilers, 12.6 kg/10^3 liters (105 lb/10^3gal) for vertical fired boilers, and 8.0 kg/10^3 liters (67 lb/10^3 gal) for all others, at full load and normal (>15%) excess air. Several combustion modifications can be employed for NO_x reduction: (1) limited excess air can reduce NO_x emissions 5-20%, (2) staged combustion 20-40%, (3) using low NO_x burners 20-50%, and (4) ammonia injection can reduce NO_x emissions 40-70% but may increase emissions of ammonia. Combinations of these modifications have been employed for further reductions in certain boilers. See Reference 23 for a discussion of these and other NO_x reducing techniques and their operational and environmental impacts.

[j] Nitrogen oxides emissions from residual oil combustion in industrial and commercial boilers are strongly related to fuel nitrogen content, estimated more accurately by the empirical relationship:
kg $NO_2/10^3$ liters $= 2.75 + 50(N)^2$ [lb $NO_2/10^3$gal $= 22 + 400(N)^2$] where N is the weight % of nitrogen in the oil. For residual oils having high (>0.5 weight %) nitrogen content, use 15 kg $NO_2/10^3$ liter (120 lb $NO_2/10^3$gal) as an emission factor.

PB89-194229

United States
Environmental Protection
Agency

Office of Air Quality
Planning And Standards
Research Triangle Park, NC 27711

EPA-450/2-89-001
April 1989

AIR

EPA

ESTIMATING AIR TOXICS EMISSIONS FROM COAL AND OIL COMBUSTION SOURCES

TABLE 4-1. SUMMARY OF TOXIC POLLUTANT EMISSION FACTORS FOR OIL COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^{12}$ Btu) Residual Oil	Distillate Oil
Arsenic	19	4.2
Beryllium	4.2	2.5
Cadmium	15.7	10.5
Chromium	21	48
Copper	280	280
Lead	28[c]	8.9[d]
Mercury	3.2	3.0
Manganese	26	14
Nickel	1260	170
POM	8.4[b]	22.5
Formaldehyde	405[e]	405[e]

[a]All emission factors are uncontrolled, and are applicable to oil-fired boilers and furnaces in all combustion sectors unless otherwise noted.

[b]This value was calculated using all available residual oil data given in Table 4-35. If the upper end of the range of available data is excluded when calculating an average value (which could be used in this table), the average factor for POM from residual oil combustion becomes 4.1 $lb/10^{12}$ BTU.

[c]Applicable to utility boilers only.

[d]Applicable to industrial, commercial, and residential boilers.

[e]The formaldehyde factors are based on very limited and relatively old data. Consult Table 4-37 and accompanying discussion for more detailed information.

PB81-225559

Emissions Assessment of Conventional Stationary Combustion Systems: Volume V: Industrial Combustion Sources

TRW, Inc.
Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

1981

U.S. Department of Commerce
National Technical Information Service

TABLE 61. COMPARISON OF EXISTING TRACE ELEMENT EMISSION FACTOR DATA WITH RESULTS OF CURRENT STUDY OF OIL-FIRED INDUSTRIAL COMBUSTION SOURCES, pg/J

	Distillate oil-fired boilers			Residual oil-fired boilers			
		Existing data			Existing data		
Element	Current study	Ref. 42	Ref. 43	Current study	Ref. 42	Ref. 21	Ref. 28
Aluminum (Al)	178	15	250	177	156	87	132
Arsenic (As)	3.5	1.3	1.5	1.2	9.1	18	12
Barium (Ba)	1.2	8.4	16	3.3	9.5	29	31
Calcium (Ca)	75	845	450	229	780	320	1428
Cadmium (Cd)	1.3	2.5	11	0.66	0.2	52	6.9
Cobalt (Co)	3.8	2.3	1.0	11	23	50	10
Chromium (Cr)	24	36	29	29	50	30	21
Copper (Cu)	37	205	160	10	93	64	350
Fluorine (F)	—	14	—	—	1.0	2.7	149
Iron (Fe)	363	545	140	83	379	411	453
Mercury (Hg)	—	1.7	1.2	—	1.9	0.9	1.5
Potassium (K)	85	60	230	261	213	777	392
Lithium (Li)	0.5	1.6	1.2	1.1	1.0	1.4	1.7
Magnesium (Mg)	42	40	210	24	111	297	2384
Nickel (Ni)	255	112	290	728	804	964	433
Lead (Pb)	24	48	42	2	7	80	34
Antimony (Sb)	—	1.7	5.7	—	21	10	25
Silicon (Si)	735	173	—	8655	1610	400	595
Vanadium (V)	195	30	2.9	366	250	3656	714
Zinc (Zn)	42	40	110	33	46	29	66

Ave. 50.9

APPENDIX B

EXISTING PERMITS AND ANNUAL OPERATING REPORTS

BEST AVAILABLE COPY

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

PERMITTEE:
University of Florida
Physical Plant Division
Bldg. 702; Room 110
Gainesville, FL 32611

I.D. Number:	31GVL01001402
Permit/Certification Number:	AO01-136997
Date of Issue:	October 12, 1987
Expiration Date:	August 1, 1992
County:	Alachua
Latitude/Longitude:	29°38'24"N; 82°20'52"W
Project:	No. 1 Steam Boiler at CHP
UTM:	E-(17)369.5; N-3279

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rules 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

For the operation of No. 1 Steam Boiler at the Central Heat Plant (CHP).

Located west of Center Drive, north of Mowery Road, University of Florida, Gainesville, Alachua County, FL.

In accordance with:

operation permit application dated August 23, 1977
renewal application dated June 21, 1982
renewal application dated July 17, 1987
BACT Determination received September 24, 1987.

BEST AVAILABLE COPY

PERMITTEE:
University of Florida at CHP
No. 1 Steam Boiler

Permit No.: A001-136997
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth herein are "Permit Conditions" and as such are binding upon the permittee and enforceable pursuant to the authority of Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is hereby placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of the "Permit Conditions" by the permittee, its agents, employees, servants or representatives.

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), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Nor 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 does not constitute 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, plant or aquatic life or property and penalties therefore caused by the construction or operation of this permitted source, nor does it allow the permittee to cause pollutuion in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall at all times 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, access to the premises, at reasonable times, where the permitted activity is located or conducted for the purpose of:

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

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

c. Sampling or monitoring 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 notify and provide the Department with the following information:

   a. a description of and cause of noncompliance; and

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

   c. 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 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 arising under the Florida Statutes or Department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes.

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

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.12 and 17-30.30, as applicable. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department.

12. This permit is required to be kept at the work site of the permitted activity during the entire period of construction or operation.

13. This permit also constitutes:

   ( ) Determination of Best Available Control Technology (BACT)
   ( ) Determination of Prevention of Significant Deterioration (PSD)
   ( ) Certification of Compliance with State Water Quality Standards (Section 401, PL 92-500)
   ( ) Compliance with New Source Performance Standards

14. The permittee shall comply with the following monitoring and record keeping requirements:

    a. Upon request, the permittee shall furnish all records and plans required under Department rules. The retention period for all records will be extended automatically, unless otherwise stipulated by the Department, during the course of any unresolved enforcement action.

    b. The permittee shall retain 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), copies of all reports required by this permit, and records of all data used to complete the application for this permit. The time period of retention shall be 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 date(s) 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 period of time furnish any information required by law which is needed to determine compliance with the permit. If the permittee 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 submitted or corrected promptly.

PERMITTEE:
University of Florida at CHP
No. 1 Steam Boiler

Permit No.: A001-136997
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

SPECIFIC CONDITIONS:

1. The maximum input rate (operating rate) is 84,320 CF/hr of natural gas or 533 gals/hr of No. 6 fuel oil and shall not be exceeded without prior approval.

2. Testing of emissions must be performed at an operating rate of at least 90% of the rate in Specific Condition (SC) No. 1, or SC No. 3 will become effective.

3. The operating rate shall not exceed 110% of the operating rate during the most recent test except for testing purposes, but shall not exceed the rate in SC No. 1. After testing at an operating rate greater than 110% of the last test operating rate, the operating rate shall not exceed 110% of the last (submitted) test operating rate until the test report at the higher rate has been reviewed and accepted by the Department.

4. The permitted maximum allowable emission rate for each pollutant is as follows:

Pollutant	Rule	Emission Rate lbs/hr	Emission Rate TPY
Particulate Matter (PM)	17-2.600(6)(b), FAC	9.59[1]	38.38
Sulfur Dioxide (SO_2)	17-2.600(6)(c), FAC	132.72[2]	530.87
Visible Emissions (VE)	17-2.600(6)(a), FAC	20% opacity, except 40% for 2 mins/hr[4]	

[1]Basis: 533 [3]gals/hr; 1.5%[4] S in FO; AP-42 emission factor.

[2]Basis: 533 [3]gals/hr; 1.5%[4] S in FO; 8.3 [3]lbs/gal.

[3]Basis: 08-23-77 application

[4]Basis: Bact Determination dated 09-21-87 which limits the fuel oil fired to "new" No. 6 fuel oil (FO) with a sulfur content not to exceed 1.5% by weight. "New" means oil refined from crude oil and has not been used.

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PERMITTEE:
University of Florida at CHP
No. 1 Steam Boiler

Permit No.: AO01-136997
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

5. Test the emission for the following pollutant(s) at the interval(s) indicated, notify GBO office* 14 days prior to testing, and submit the test report documentation to the GBO office* within 45 days after completion of the testing:

Pollutant	Interval from 01-20-87
SO_2	12 months - send certified fuel oil analysis with the annual operation report if this unit is fired with No. 6 oil for more than 400 hr. the previous calendar year.
VE	12 months[1,2,3]

[1]Basis: Rule 17-2.700(2)(a)4., FAC - test annually unless otherwise specified.

[2]Basis: Rule 17-2.700(2)(a)3., FAC - test not required when liquid fuel is burned for a total of no more than 400 hours.

[3]Basis: If this unit was fired only with natural gas during the previous calendar year, so state in the annual operation report.

*Gainesville Branch Office (GBO) located at 5700 SW 34th St., Suite 1204, Gainesville, FL 32608. Phone 904/377-7528.

Tests and test reports shall comply with the requirements of Florida Administrative Code Rule 17-2.700(6) and (7), respectively.

6. In each test report, submit the maximum input/production rate at which this source was operated since the most recent test.

7. Submit an annual operation report for this source on the form supplied by the Department for each calendar year on or before March 1.

8. Any revision(s) to a permit (and application) must be submitted and approved prior to implementing.

9. Forms for renewal will be sent 5 months prior to August 1, 1992 and the completed forms with test results are due 90 days prior to August 1, 1992.

Issued this 12 day of October, 1987

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

BFW

Ernest E. Frey

Ernest E. Frey, District Manager

Best Available Control Technology (BACT) Determination
University of Florida
Alachua County

The applicant plans to operate five boilers (Heat Plant No. 2) located at their facility in Gainesville, Florida. The five boilers which will be fired on a rotating basis with a maximum of three boilers operating simultaneously are capable of firing either natural gas or No. 6 fuel oil.

A BACT determination is required for the source as set forth in the Florida Administrative Code Rule 17-2.600 (6) - Emissions Limiting and Performance Standards.

BACT Determination Request by the Applicant:

Particulate and sulfur dioxide emissions to be controlled by the firing of natural gas or by firing No. 6 fuel oil containing 2.0 percent sulfur, by weight.

Date of Receipt of a BACT Application:

July 17, 1987

Review Group Members:

The determination was based upon comments received from the Stationary Source Control Section and the Northeast District.

Review Determined by DER:

The amount of particulate and sulfur dioxide emissions from the boilers will be limited by the firing of natural gas or firing new [1] No. 6 fuel oil having a sulfur content not to exceed 1.5 percent, by weight.

Visible Emissions	Not to exceed 20% opacity. 40% opacity is permitted for not more than two minutes in any one hour.

DER Method 9 (17-2.700(6)(a)9, FAC) will be used to determine compliance with the opacity standard.

[1] The term "new" means an oil which has been refined from crude oil and has not been used.

BACT Determination Rationale:

Sulfur in fuel oil is a primary air pollution concern in that most of the fuel sulfur becomes SO_2. The emission factors for SO_2 and particulate emissions from oil burning are related to

the sulfur content. The emission factors used by the applicant and the Department are from AP-42, Table 1.3-1.

The applicant has stated that the maximum steam load would require approximately 44 percent of the combined boiler capacity. At this level of operation, dispersion modeling indicates that the ambient air quality standards (AAQS) would not be exceeded for either particulates or sulfur dioxide. There is also no exceedances of the PSD increment since the boilers were each installed prior to the baseline date of December 27, 1977 and therefore do not consume increment.

Although the air quality impacts analysis does not indicate exceedances of the standards when firing the proposed 2.0% sulfur fuel oil, the economic impact of using lower sulfur content fuels needs to be addressed. A review of previous BACT determinations for boilers of similar size which fire No. 6 fuel oil indicates that the sulfur content has generally been limited to 1.5%.

In accordance with the 1.5% sulfur content limitation which is generally required for this type of boiler, the cost of fuel switching can be determined. The applicant has a contract rate of $20.65 per barrel for 2.0 percent No. 6 fuel oil. At the contract rate, No. 6 fuel oil with a sulfur content not to exceed 1.5 percent would cost $21.15 which corresponds to an additional 1.19 cents per gallon.

Assuming the maximum firing rate of 25 percent of total annual, capacity , the additional annual cost of using the 1.5% sulfur content fuel oil instead of the proposed 2.0% sulfur content No. 6 fuel oil would be $97,129. The sulfur dioxide reductions from switching to the 1.5% sulfur fuel oil are estimated to be 313.5 tons per year. Based on this reduction, the annual cost per ton of sulfur dioxide removed is approximately $310.00 which is less than the EPA guideline of up to $2,000 per ton for sulfur dioxide removal.

Based on the information presented in this analysis, the Bureau has determined that BACT is represented by the firing of either natural gas or No. 6 fuel oil with a sulfur content not to exceed 1.5 percent, by weight.

Details of the Analysis May be Obtained by Contacting:

Barry Andrews, P.E. BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Recommended by:

C. H. Fancy, P.E.
Deputy Bureau Chief, BAQM

9/16/87
Date

Approved by:

Dale Twachtmann, Secretary

21 Sept 87
Date

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STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

PERMITTEE:
University of Florida
Physical Plant Division
Bldg. 702; Room 110
Gainesville, FL 32611

I.D. Number:	31GVL01001403
Permit/Certification Number:	AO01-136998
Date of Issue:	October 12, 1987
Expiration Date:	August 1, 1992
County:	Alachua
Latitude/Longitude:	29°38'24"N; 82°20'52"W
Project:	No. 2 Steam Boiler at CHP
UTM:	E-(17)369.5; N-3279.4

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rules 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

For the operation of No. 2 Steam Boiler at the Central Heat Plant (CHP).

Located west of Center Drive, north of Mowery Road, University of Florida, Gainesville, Alachua County, FL.

In accordance with:

operation permit application dated August 23, 1977
renewal application dated June 21, 1982
renewal application dated July 17, 1987
BACT Determination received September 24, 1987.

PERMITTEE:
University of Florida at CHP
No. 2 Steam Boiler

Permit No.: A001-136998
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth herein are "Permit Conditions" and as such are binding upon the permittee and enforceable pursuant to the authority of Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is hereby placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of the "Permit Conditions" by the permittee, its agents, employees, servants or representatives.

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), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Nor 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 does not constitute 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, plant or aquatic life or property and penalties therefore caused by the construction or operation of this permitted source, nor does it allow the permittee to cause pollutuion in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall at all times 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, access to the premises, at reasonable times, where the permitted activity is located or conducted for the purpose of:

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

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

c. Sampling or monitoring 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 notify and provide the Department with the following information:

a. a description of and cause of noncompliance; and

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

c. 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 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 arising under the Florida Statutes or Department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes.

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

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.12 and 17-30.30, as applicable. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department.

12. This permit is required to be kept at the work site of the permitted activity during the entire period of construction or operation.

13. This permit also constitutes:

( ) Determination of Best Available Control Technology (BACT)
( ) Determination of Prevention of Significant Deterioration (PSD)
( ) Certification of Compliance with State Water Quality Standards (Section 401, PL 92-500)
( ) Compliance with New Source Performance Standards

14. The permittee shall comply with the following monitoring and record keeping requirements:

    a. Upon request, the permittee shall furnish all records and plans required under Department rules. The retention period for all records will be extended automatically, unless otherwise stipulated by the Department, during the course of any unresolved enforcement action.

    b. The permittee shall retain 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), copies of all reports required by this permit, and records of all data used to complete the application for this permit. The time period of retention shall be 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 date(s) 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 period of time furnish any information required by law which is needed to determine compliance with the permit. If the permittee 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 submitted or corrected promptly.

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PERMITTEE:	Permit No.: A001-136998
University of Florida at CHP	Date of Issue: October 12, 1987
No. 2 Steam Boiler	Expiration Date: August 1, 1992

SPECIFIC CONDITIONS:

1. The maximum input rate (operating rate) is 84,320 CF/hr of natural gas or 533 gals/hr of No. 6 fuel oil and shall not be exceeded without prior approval.

2. Testing of emissions must be performed at an operating rate of at least 90% of the rate in Specific Condition (SC) No.1, or SC No. 3 will become effective.

3. The operating rate shall not exceed 110% of the operating rate during the most recent test except for testing purposes, but shall not exceed the rate in SC No. 1. After testing at an operating rate greater than 110% of the last test operating rate, the operating rate shall not exceed 110% of the last (submitted) test operating rate until the test report at the higher rate has been reviewed and accepted by the Department.

4. The permitted maximum allowable emission rate for each pollutant is as follows:

Pollutant	Rule	Emission Rate lbs/hr	Emission Rate TPY
Particulate Matter (PM)	17-2.600(6)(b), FAC	9.59[1]	38.38
Sulfur Dioxide (SO_2)	17-2.600(6)(c), FAC	132.72[2]	530.87
Visible Emissions (VE)	17-2.600(6)(a), FAC	20% opacity, except 40% for 2 mins/hr	

[1]Basis: 533 [3]gals/hr; 1.5%[4] S in FO; AP-42 emission factor.

[2]Basis: 533 [3]gals/hr; 1.5%[4] S in FO; 8.3 [3]lbs/gal.

[3]Basis: 08-23-77 application

[4]Basis: Bact Determination dated 09-21-87 which limits the fuel oil fired to "new" No. 6 fuel oil (FO) with a sulfur content not to exceed 1.5% by weight. "New" means oil refined from crude oil and has not been used.

5. Test the emission for the following pollutant(s) at the interval(s) indicated, notify GBO office* 14 days prior to testing, and submit the test report documentation to the GBO office* within 45 days after completion of the testing:

Pollutant	Interval from 01-20-87
SO_2	12 months - send certified fuel oil analysis with the annual operation report if this unit is fired with No. 6 oil for more than 400 hr. the previous calendar year.
VE	12 months[1,2,3]

[1]Basis: Rule 17-2.700(2)(a)4., FAC - test annually unless otherwise specified.

[2]Basis: Rule 17-2.700(2)(a)3., FAC - test not required when liquid fuel is burned for a total of no more than 400 hours.

[3]Basis: If this unit was fired only with natural gas during the previous calendar year, so state in the annual operation report.

*Gainesville Branch Office (GBO) located at 5700 SW 34th St., Suite 1204, Gainesville, FL 32608. Phone 904/377-7528.

Tests and test reports shall comply with the requirements of Florida Administrative Code Rule 17-2.700(6) and (7), respectively.

6. In each test report, submit the maximum input/production rate at which this source was operated since the most recent test.

7. Submit an annual operation report for this source on the form supplied by the Department for each calendar year on or before March 1.

8. Any revision(s) to a permit (and application) must be submitted and approved prior to implementing.

9. Forms for renewal will be sent 5 months prior to August 1, 1992 and the completed forms with test results are due 90 days prior to August 1, 1992.

Issued this 12 day of October, 1987

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

Ernest E. Frey

Ernest E. Frey, District Manager

Best Available Control Technology (BACT) Determination
University of Florida
Alachua County

The applicant plans to operate five boilers (Heat Plant No. 2) located at their facility in Gainesville, Florida. The five boilers which will be fired on a rotating basis with a maximum of three boilers operating simultaneously are capable of firing either natural gas or No. 6 fuel oil.

A BACT determination is required for the source as set forth in the Florida Administrative Code Rule 17-2.600 (6) - Emissions Limiting and Performance Standards.

BACT Determination Request by the Applicant:

Particulate and sulfur dioxide emissions to be controlled by the firing of natural gas or by firing No. 6 fuel oil containing 2.0 percent sulfur, by weight.

Date of Receipt of a BACT Application:

July 17, 1987

Review Group Members:

The determination was based upon comments received from the Stationary Source Control Section and the Northeast District.

Review Determined by DER:

The amount of particulate and sulfur dioxide emissions from the boilers will be limited by the firing of natural gas or firing new [1] No. 6 fuel oil having a sulfur content not to exceed 1.5 percent, by weight.

Visible Emissions	Not to exceed 20% opacity. 40% opacity is permitted for not more than two minutes in any one hour.

DER Method 9 (17-2.700(6)(a)9, FAC) will be used to determine compliance with the opacity standard.

[1] The term "new" means an oil which has been refined from crude oil and has not been used.

BACT Determination Rationale:

Sulfur in fuel oil is a primary air pollution concern in that most of the fuel sulfur becomes SO_2. The emission factors for SO_2 and particulate emissions from oil burning are related to

the sulfur content. The emission factors used by the applicant and the Department are from AP-42, Table 1.3-1.

The applicant has stated that the maximum steam load would require approximately 44 percent of the combined boiler capacity. At this level of operation, dispersion modeling indicates that the ambient air quality standards (AAQS) would not be exceeded for either particulates or sulfur dioxide. There is also no exceedances of the PSD increment since the boilers were each installed prior to the baseline date of December 27, 1977 and therefore do not consume increment.

Although the air quality impacts analysis does not indicate exceedances of the standards when firing the proposed 2.0% sulfur fuel oil, the economic impact of using lower sulfur content fuels needs to be addressed. A review of previous BACT determinations for boilers of similar size which fire No. 6 fuel oil indicates that the sulfur content has generally been limited to 1.5%.

In accordance with the 1.5% sulfur content limitation which is generally required for this type of boiler, the cost of fuel switching can be determined. The applicant has a contract rate of $20.65 per barrel for 2.0 percent No. 6 fuel oil. At the contract rate, No. 6 fuel oil with a sulfur content not to exceed 1.5 percent would cost $21.15 which corresponds to an additional 1.19 cents per gallon.

Assuming the maximum firing rate of 25 percent of total annual, capacity , the additional annual cost of using the 1.5% sulfur content fuel oil instead of the proposed 2.0% sulfur content No. 6 fuel oil would be $97,129. The sulfur dioxide reductions from switching to the 1.5% sulfur fuel oil are estimated to be 313.5 tons per year. Based on this reduction, the annual cost per ton of sulfur dioxide removed is approximately $310.00 which is less than the EPA guideline of up to $2,000 per ton for sulfur dioxide removal.

Based on the information presented in this analysis, the Bureau has determined that BACT is represented by the firing of either natural gas or No. 6 fuel oil with a sulfur content not to exceed 1.5 percent, by weight.

affected by diurnal land-sea breezes. Therefore, these data are considered to be the most representative of weather conditions occurring at the plant site.

The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling height. The wind speed, cloud cover, and cloud ceiling values were used in the ISCST meteorological preprocessor program (RAMMET) to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated from the radiosonde data at Waycross using the Holzworth approach (Holzworth, 1972). The hourly surface data and mixing heights were used to develop a sequential series of hourly meteorological data (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions at the NWS stations are classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector to account for the expected variability in air flow. These calculations were performed using the RAMMET meteorological preprocessor program.

6.3 EMISSION INVENTORY

Stack operating parameters and air emission rates for the proposed unit were presented in Section 2.0.

Modeling of the proposed unit demonstrated that the facility's PM10 and CO impacts are below the significant impact levels. Further modeling for this facility is not required.

6.4 RECEPTOR LOCATIONS

In the ISCST modeling, concentrations were predicted for the screening phase using a polar receptor grid. A description of the receptor locations for determining maximum predicted impacts is as follows:

The receptor grid for the short-term CO modeling included rings at 53; 70; 100; 400; 700; 1,000; 1,300; 1,600; 2,000; and 2,500 meters. The 53-meter distance is the closest allowable ring distance (3 x building height) for assessing the impacts due to building wake effects. Elevations of 77 and 85 ft were chosen for all receptors at 53 and 70 meters, respectively. These elevations are representative of the highest terrain near the site.

After the screening modeling was completed, refined modeling was conducted using a receptor grid centered on the receptor that had the highest concentration from the screening analysis. The receptors were located at intervals of 100 m between the distances considered in the screening phase, along 9 radials spaced at 2-degree increments, centered on the radial along which the maximum concentration was produced. For example, if the maximum concentration was produced along the 90-degree radial at a distance of 1.6 km, the refined receptor grid would consist of receptors at the following locations:

Directions (degrees)	Distance (km)
82, 84, 86, 88, 90, 92, 94, 96, 98	1.3, 1.4, 1.5, 1.6, 1.7, 1.8, and 1.9 per direction

To ensure that a valid maximum concentration was calculated, concentrations were predicted using the refined grid for the entire year that produced the highest concentration from the screening receptor grid. If maximum concentrations for other years were within 10 percent of that for the highest year, they also were refined.

Refined modeling analysis was not performed for the annual averaging period because the spatial distribution of annual average concentrations are not expected to vary significantly from those produced from the screening analysis.

The minimum distance of the proposed source from the Chassahowitzka Wilderness Area is approximately 125 km. Since the impacts of this source are below significant impact levels, impacts at the PSD Class I area were not performed.

6.5 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with buildings and structures planned at the plant, the stack for the proposed turbine will be less than GEP. Therefore, the potential for building downwash to occur was considered in the modeling analysis.

The procedures used for addressing the effects of building downwash are those recommended in the ISC Dispersion Model User's Guide. The building height, length, and width are input to the model, which uses these parameters to modify the dispersion parameters. 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. If this method is used, then direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10-degree sector. The features of the Schulman and Scire method are as follows:

1. Reduced plume rise as a result of initial plume dilution,
2. Enhanced plume spread as a linear function of the effective plume height, and
3. Specification of building dimensions as a function of wind direction.

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. For this method, the ISCST model calculates the area of the building using the length and width, assumes the area is representative of a circle, and then calculates a building width by determining the diameter of the circle. If a specific width is to be modeled, then the value input to the model must be adjusted according to the following formula:

Details of the Analysis May be Obtained by Contacting:

Barry Andrews, P.E. BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Recommended by:

C. H. Fancy, P.E.
Deputy Bureau Chief, BAQM

1/16/87
Date

Approved by:

Dale Twachtmann, Secretary

21 Sept 87
Date

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

PERMITTEE:
University of Florida
Physical Plant Division
Bldg. 702; Room 110
Gainesville, FL 32611

I.D. Number: 31GVL01001404
Permit/Certification Number: A001-136999
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992
County: Alachua
Latitude/Longitude: 29°38'24"N; 82°20'52"W
Project: No. 3 Steam Boiler at CHP
UTM: E-(17)369.5; N-3279.4

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rules 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

For the operation of No. 3 Steam Boiler at the Central Heat Plant (CHP).

Located west of Center Drive, north of Mowery Road, University of Florida, Gainesville, Alachua County, FL.

In accordance with:

operation permit application dated August 23, 1977
renewal application dated June 21, 1982
renewal application dated July 17, 1987
BACT Determination received September 24, 1987.

PERMITTEE:
University of Florida at CHP
No. 3 Steam Boiler

Permit No.: A001-136999
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth herein ar "Permit Conditions" and as such are binding upon the permittee and enforceable pursuan to the authority of Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is hereby placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of the "Permit Conditions" by the permittee, its agents, employees, servants or representatives.

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), Florida Statutes, the issuance o this permit does not convey any vested rights or any exclusive privileges. Nor does i 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 does not constitute 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 o 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, plant or aquatic life or property and penalties therefore caused by the construction or operation of this permitted source, nor does it allow the permittee to cause pollutuion in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.

6. The permittee shall at all times properly operate and maintain the facility and system 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, access to the premises, at reasonable times, where the permitted activity is located or conducted for the purpose of:

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

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

c. Sampling or monitoring 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 notify and provide the Department with the following information:

a. a description of and cause of noncompliance; and

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

c. 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 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 arising under the Florida Statutes or Department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes.

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

11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 17-4.12 and 17-30.30, as applicable. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department.

12. This permit is required to be kept at the work site of the permitted activity during the entire period of construction or operation.

13. This permit also constitutes:

( ) Determination of Best Available Control Technology (BACT)
( ) Determination of Prevention of Significant Deterioration (PSD)
( ) Certification of Compliance with State Water Quality Standards (Section 401, PL 92-500)
( ) Compliance with New Source Performance Standards

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PERMITTEE:
University of Florida at CHP
No. 3 Steam Boiler

Permit No.: A001-136999
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

14. The permittee shall comply with the following monitoring and record keeping requirements:

    a. Upon request, the permittee shall furnish all records and plans required under Department rules. The retention period for all records will be extended automatically, unless otherwise stipulated by the Department, during the course of any unresolved enforcement action.

    b. The permittee shall retain 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), copies of all reports required by this permit, and records of all data used to complete the application for this permit. The time period of retention shall be 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 date(s) 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 period of time furnish any information required by law which is needed to determine compliance with the permit. If the permittee 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 submitted or corrected promptly.

PERMITTEE:
University of Florida at CHP
No. 3 Steam Boiler

Permit No.: A001-136999
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

SPECIFIC CONDITIONS:

1. The maximum input rate (operating rate) is 153,000 CF/hr of natural gas or 1066.6 gals/hr of No. 6 fuel oil and shall not be exceeded without prior approval.

2. Testing of emissions must be performed at an operating rate of at least 90% of the rate in Specific Condition (SC) No. 1, or SC No. 3 will become effective.

3. The operating rate shall not exceed 110% of the operating rate during the most recent test except for testing purposes, but shall not exceed the rate in SC No. 1. After testing at an operating rate greater than 110% of the last test operating rate, the operating rate shall not exceed 110% of the last (submitted) test operating rate until the test report at the higher rate has been reviewed and accepted by the Department.

4. The permitted maximum allowable emission rate for each pollutant is as follows:

Pollutant	Rule	Emission Rate lbs/hr	Emission Rate TPY
Particulate Matter (PM)	17-2.600(6)(b), FAC	19.20[1]	76.80
Sulfur Dioxide (SO_2)	17-2.600(6)(c), FAC	265.58[2]	1062.33
Visible Emissions (VE)	17-2.600(6)(a), FAC	20% opacity, except 40% for 2 mins/hr	

[1]Basis: 1066.6 [3]gals/hr; 1.5%[4] S in FO; AP-42 emission factor.

[2]Basis: 1066.6 [3]gals/hr; 1.5%[4] S in FO; 8.3 [3]lbs/gal.

[3]Basis: 08-23-77 application

[4]Basis: Bact Determination dated 09-21-87 which limits the fuel oil fired to "new" No. 6 fuel oil (FO) with a sulfur content not to exceed 1.5% by weight. "New" means oil refined from crude oil and has not been used.

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PERMITTEE:
University of Florida at CHP
No. 3 Steam Boiler

Permit No.: AO01-136999
Date of Issue: October 12, 1987
Expiration Date: August 1, 1992

5. Test the emission for the following pollutant(s) at the interval(s) indicated, notify GBO office* 14 days prior to testing, and submit the test report documentation to the GBO office* within 45 days after completion of the testing:

Pollutant	Interval from 01-20-87
SO_2	12 months - send certified fuel oil analysis with the annual operation report if this unit is fired with No. 6 oil for more than 400 hr. the previous calendar year.
VE	12 months[1,2,3]

[1]Basis: Rule 17-2.700(2)(a)4., FAC - test annually unless otherwise specified.

[2]Basis: Rule 17-2.700(2)(a)3., FAC - test not required when liquid fuel is burned for a total of no more than 400 hours.

[3]Basis: If this unit was fired only with natural gas during the previous calendar year, so state in the annual operation report.

*Gainesville Branch Office (GBO) located at 5700 SW 34th St., Suite 1204, Gainesville, FL 32608. Phone 904/377-7528.

Tests and test reports shall comply with the requirements of Florida Administrative Code Rule 17-2.700(6) and (7), respectively.

6. In each test report, submit the maximum input/production rate at which this source was operated since the most recent test.

7. Submit an annual operation report for this source on the form supplied by the Department for each calendar year on or before March 1.

8. Any revision(s) to a permit (and application) must be submitted and approved prior to implementing.

9. Forms for renewal will be sent 5 months prior to August 1, 1992 and the completed forms with test results are due 90 days prior to August 1, 1992.

Issued this 12 day of October, 1987

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

Ernest E. Frey

Ernest E. Frey, District Manager

Best Available Control Technology (BACT) Determination
University of Florida
Alachua County

The applicant plans to operate five boilers (Heat Plant No. 2) located at their facility in Gainesville, Florida. The five boilers which will be fired on a rotating basis with a maximum of three boilers operating simultaneously are capable of firing either natural gas or No. 6 fuel oil.

A BACT determination is required for the source as set forth in the Florida Administrative Code Rule 17-2.600 (6) - Emissions Limiting and Performance Standards.

BACT Determination Request by the Applicant:

Particulate and sulfur dioxide emissions to be controlled by the firing of natural gas or by firing No. 6 fuel oil containing 2.0 percent sulfur, by weight.

Date of Receipt of a BACT Application:

July 17, 1987

Review Group Members:

The determination was based upon comments received from the Stationary Source Control Section and the Northeast District.

Review Determined by DER:

The amount of particulate and sulfur dioxide emissions from the boilers will be limited by the firing of natural gas or firing new [1] No. 6 fuel oil having a sulfur content not to exceed 1.5 percent, by weight.

Visible Emissions	Not to exceed 20% opacity. 40% opacity is permitted for not more than two minutes in any one hour.

DER Method 9 (17-2.700(6)(a)9, FAC) will be used to determine compliance with the opacity standard.

[1] The term "new" means an oil which has been refined from crude oil and has not been used.

BACT Determination Rationale:

Sulfur in fuel oil is a primary air pollution concern in that most of the fuel sulfur becomes SO_2. The emission factors for SO_2 and particulate emissions from oil burning are related to

the sulfur content. The emission factors used by the applicant and the Department are from AP-42, Table 1.3-1.

The applicant has stated that the maximum steam load would require approximately 44 percent of the combined boiler capacity. At this level of operation, dispersion modeling indicates that the ambient air quality standards (AAQS) would not be exceeded for either particulates or sulfur dioxide. There is also no exceedances of the PSD increment since the boilers were each installed prior to the baseline date of December 27, 1977 and therefore do not consume increment.

Although the air quality impacts analysis does not indicate exceedances of the standards when firing the proposed 2.0% sulfur fuel oil, the economic impact of using lower sulfur content fuels needs to be addressed. A review of previous BACT determinations for boilers of similar size which fire No. 6 fuel oil indicates that the sulfur content has generally been limited to 1.5%.

In accordance with the 1.5% sulfur content limitation which is generally required for this type of boiler, the cost of fuel switching can be determined. The applicant has a contract rate of $20.65 per barrel for 2.0 percent No. 6 fuel oil. At the contract rate, No. 6 fuel oil with a sulfur content not to exceed 1.5 percent would cost $21.15 which corresponds to an additional 1.19 cents per gallon.

Assuming the maximum firing rate of 25 percent of total annual, capacity , the additional annual cost of using the 1.5% sulfur content fuel oil instead of the proposed 2.0% sulfur content No. 6 fuel oil would be $97,129. The sulfur dioxide reductions from switching to the 1.5% sulfur fuel oil are estimated to be 313.5 tons per year. Based on this reduction, the annual cost per ton of sulfur dioxide removed is approximately $310.00 which is less than the EPA guideline of up to $2,000 per ton for sulfur dioxide removal.

Based on the information presented in this analysis, the Bureau has determined that BACT is represented by the firing of either natural gas or No. 6 fuel oil with a sulfur content not to exceed 1.5 percent, by weight.

Details of the Analysis May be Obtained by Contacting:

Barry Andrews, P.E. BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Recommended by:

C. H. Fancy, P.E.
Deputy Bureau Chief, BAQM

9/16/87
Date

Approved by:

Dale Twachtmann, Secretary

21 Sept 87
Date

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

PERMITTEE:

Mr. Ken Kisida, Utilities Manager
University of Florida
Physical Plant Division
Building 702, Room 110
Gainesville, Florida 32611

I.D. Number: 31GVL01001411
Permit/Cert Number: A001-136570
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992
County: Alachua
Lat/Long: 29°38'24"N/82°20'52"W
Section/Township/Range:
Project: No. 4 Steam Boiler at CHP
UTM: E-(17) 369.5; N-3279.4

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rule(s) 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the department and made a part hereof and specifically described as follows:

For the operation of No. 4 Steam Boiler at the Central Heat Plant (CHP).

Located west of Center Drive, north of Mowery Road, University of Florida, Gainesville, Alachua County, Florida.

In accordance with operational permit application dated August 23, 1977, renewal application dated June 21, 1982, renewal application dated July 8, 1987 and BACT Determination received September 24, 1987.

PERMITTEE:

University of Florida
No. 4 Steam Boiler at CHP

I.D. Number: 31GVL01001411
Permit Number: A001-136570
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth herein are "Permit Conditions" and as such are binding upon the permittee and enforceable pursuant to the authority of Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is hereby placed on notice that the department will review this permit periodically and may initiate enforcement action for any violation of the "Permit Conditions" by the permittee, its agents, employees, servants, or representatives.

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), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Nor 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 does not constitute 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, plant or aquatic life or property and penalties therefore caused by the construction or operation of this permitted source, nor does it allow the permittee to cause pollution in contravention of Florida Statutes and department rules, unless specifically authorized by an order from the department.

6. The permittee shall at all times 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, access to the premises, at reasonable times, where the permitted activity is located or conducted for the purpose of:

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

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

c. Sampling or monitoring 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 notify and provide the department with the following information:

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

b. the period of non-compliance, including exact 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 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 arising under the Florida Statutes or department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes.

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

11. This permit is transferable only upon department approval in accordance with Florida Administrative Code Rules 17-4.12 and 17-30.30, as applicable. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the department.

12. This permit is required to be kept at the work site of the permitted activity during the entire period of construction or operation.

PERMITTEE:

University of Florida
No. 4 Stem Boiler at CHP

I.D. Number: 31GVL01001411
Permit Number: A001-136570
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

13. This permit also constitutes:

( ) Determination of Best Available Control Technology (BACT)
( ) Determination of Prevention of Significant Deterioration (PSD)
( ) Certification of Compliance with State Water Quality Standards
( ) (Section 401, PL 92-500)
( ) Compliance with New Source Performance Standards

14. The permittee shall comply with the following monitoring and record keeping requirements:

a. Upon request, the permittee shall furnish all records and plans required under department rules. The retention period for all records will be extended automatically, unless otherwise stipulated by the department, during the course of any unresolved enforcement action.

b. The permittee shall retain 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), copies of all reports required by this permit, and records of all data used to complete the application for this permit. The time period of retention shall be 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 date(s) 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 period of time furnish any information required by law which is needed to determine compliance with the permit. If the permittee 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 submitted or corrected promptly.

PERMITTEE:

University of Florida
No. 4 Steam Boiler at CHP

I.D. Number: 31GVL01001411
Permit Number: A001-136570
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

SPECIFIC CONDITIONS:

1. The maximum input rate (operating rate) is 68.333 cf/hr of natural gas or 444 gals/hr of No. 6 fuel oil and shall not be exceeded without prior approval.

2. Testing of emissions must be performed at an operating rate of at least 90% of the rate in Specific Condition (SC) No. 1, or SC No. 3 will become effective.

3. The operating rate shall not exceed 110% of the operating rate during the most recent test except for testing purposes, but shall not exceed the rate in SC No. 1. After testing at an operating rate greater than 110% of the last test operating rate, the operating rate shall not exceed 110% of the last (submitted) test operating rate until the test report at the higher rate has been reviewed and accepted by the Department.

4. The permitted maximum allowable emission rate for each pollutant is as follows:

Pollutant	Regulation	Emission Rate lbs/hr	Emission Rate TPY
Particulate Matter (PM)	17-2.600(6)(b), FAC	7.99[1]	31.97
Sulfur Dioxide (SO_2)	17-2.600(6)(c), FAC	110.56[2]	442.23
Visible Emissions (VE)	17-2.600(6)(a), FAC	20% opacity, except 40% for 2 mins/hr	

[1]Basis: 444[3] gals/hr; 1.5%[4] S in FO; AP-42 emission factor

[2]Basis: 444[3] gals/hr; 1.5%[4] S in FO; 8.3[3] lbs/gal

[3]Basis: 08-23-77 application

[4]Basis: BACT determination dated September 21, 1987 which limits the fuel fired to "new" No. 6 fuel oil (FO) with a sulfur content not to exceed 1.5% by weight. "New" means oil refined from crude oil and has not been used.

5. Test the emission for the following pollutant(s) at the interval(s) indicated, notify GBO office* fourteen (14) days prior to testing, and submit the test report documentations to GBO office* within 45 days after completion of the testing:

Pollutant	Interval from 01-20-87
SO_2	12 months; Send certified fuel oil analysis with the annual opn rpt if this unit is fired with No. 6 oil for more than 400 hours the previous calendar year.

* GBO at 5700 S.W. 34th Street, Suite 1204, Gainesville, Florida 32608
Phone No. (904)377-7528

PERMITTEE:

University of Florida
No. 4 Steam Boiler at CHP

I.D. Number: 31GVL01001411
Permit Number: A001-136570
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

CONDITIONAL VE BASED ON FUEL USED

Pollutant	Interval from 01-20-87
VE	12 months [1,2,3]

[1]Basis: Rule 17-2.700(2)(a)4., FAC - test annually unless otherwise specified
[2]Basis: Rule 17-2.700(2)(a)3., FAC - test not required when liquid fuel is burned for a total of no more than 400 hours
[3]Basis: If this unit was fired only with natural gas during the previous calendar year, so state in the annual operation report

Tests and test reports shall comply with the requirements of FAC Rule 17-2.700(6) and (7), respectively.

6. In each test report, submit the maximum input/production rate at which this source was operated since the most recent test.

7. Submit an annual operation report for this source on the form supplied by the Department for each calendar year on or before March 1.

8. Any revision(s) to a permit (and application) must be submitted and approved prior to implementing.

9. Forms for the renewal will be sent five (5) months prior to August 1, 1992 and the completed forms with test results are due 90 days prior to August 1, 1992 .

Issued this 1st day of October 1987

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Ernest E. Frey

Ernest E. Frey, District Manager

BEST AVAILABLE COPY

Best Available Control Technology (BACT) Determination
University of Florida
Alachua County

The applicant plans to operate five boilers (Heat Plant No. 2) located at their facility in Gainesville, Florida. The five boilers which will be fired on a rotating basis with a maximum of three boilers operating simultaneously are capable of firing either natural gas or No. 6 fuel oil.

A BACT determination is required for the source as set forth in the Florida Administrative Code Rule 17-2.600 (6) - Emissions Limiting and Performance Standards.

BACT Determination Request by the Applicant:

Particulate and sulfur dioxide emissions to be controlled by the firing of natural gas or by firing No. 6 fuel oil containing 2.0 percent sulfur, by weight.

Date of Receipt of a BACT Application:

July 17, 1987

Review Group Members:

The determination was based upon comments received from the Stationary Source Control Section and the Northeast District.

Review Determined by DER:

The amount of particulate and sulfur dioxide emissions from the boilers will be limited by the firing of natural gas or firing new [1] No. 6 fuel oil having a sulfur content not to exceed 1.5 percent, by weight.

Visible Emissions	Not to exceed 20% opacity. 40% opacity is permitted for not more than two minutes in any one hour.

DER Method 9 (17-2.700(6)(a)9, FAC) will be used to determine compliance with the opacity standard.

[1] The term "new" means an oil which has been refined from crude oil and has not been used.

BACT Determination Rationale:

Sulfur in fuel oil is a primary air pollution concern in that most of the fuel sulfur becomes SO_2. The emission factors for SO_2 and particulate emissions from oil burning are related to

the sulfur content. The emission factors used by the applicant and the Department are from AP-42, Table 1.3-1.

The applicant has stated that the maximum steam load would require approximately 44 percent of the combined boiler capacity. At this level of operation, dispersion modeling indicates that the ambient air quality standards (AAQS) would not be exceeded for either particulates or sulfur dioxide. There is also no exceedances of the PSD increment since the boilers were each installed prior to the baseline date of December 27, 1977 and therefore do not consume increment.

Although the air quality impacts analysis does not indicate exceedances of the standards when firing the proposed 2.0% sulfur fuel oil, the economic impact of using lower sulfur content fuels needs to be addressed. A review of previous BACT determinations for boilers of similar size which fire No. 6 fuel oil indicates that the sulfur content has generally been limited to 1.5%.

In accordance with the 1.5% sulfur content limitation which is generally required for this type of boiler, the cost of fuel switching can be determined. The applicant has a contract rate of $20.65 per barrel for 2.0 percent No. 6 fuel oil. At the contract rate, No. 6 fuel oil with a sulfur content not to exceed 1.5 percent would cost $21.15 which corresponds to an additional 1.19 cents per gallon.

Assuming the maximum firing rate of 25 percent of total annual capacity , the additional annual cost of using the 1.5% sulfur content fuel oil instead of the proposed 2.0% sulfur content No. 6 fuel oil would be $97,129. The sulfur dioxide reductions from switching to the 1.5% sulfur fuel oil are estimated to be 313.5 tons per year. Based on this reduction, the annual cost per ton of sulfur dioxide removed is approximately $310.00 which is less than the EPA guideline of up to $2,000 per ton for sulfur dioxide removal.

Based on the information presented in this analysis, the Bureau has determined that BACT is represented by the firing of either natural gas or No. 6 fuel oil with a sulfur content not to exceed 1.5 percent, by weight.

Details of the Analysis May be Obtained by Contacting:

Barry Andrews, P.E. BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Recommended by:

C. H. Fancy, P.E.
Deputy Bureau Chief, BAQM

9/16/87
Date

Approved by:

Dale Twachtmann, Secretary

21 Sept 87
Date

BEST AVAILABLE COPY

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904)

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

APPLICATION FOR RENEWAL OF PERMIT TO OPERATE AIR POLLUTION SOURCE(S)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: No. 4 Steam Boiler Renewal of DER Permit No. A001-57683

Company Name: UNIVERSITY OF FLORIDA 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):

No. 4 Steam Boiler second Black Steel Stack From the North End of Plant

Source Location: Street: Bldg. 473 North of Mowery ROAD City: GAINESVILLE

UTM: East ______ North ______

Latitude: __ __° __ __' __ __"N. Longitude: __ __° __ __' __ __"W.

1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [ ] Yes [X] No
If minor alterations have occurred, describe on a separate sheet and attach.

3. Attach the last compliance test report required per permit conditions if not submitted previously.

4. Have previous permit conditions been adhered to? [X] Yes [ ] No If no, explain on a separate sheet and attach.

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [X] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [X] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [ ] Yes [X] No If no, please attach.

Best Available Copy

8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate lbs/hr

B. Product Weight (lbs/hr): 50,000

C. Fuels No. 6 Oil

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input (MMBTU/hr)
No. 6 Fuel Oil		250 GAL	148,000 BTU per GAL, MIN

D. Normal Equipment Operating Time: hrs/day 24; days/wk ____; wks/yr ____;

hrs/yr (power plants only) ____; if seasonal, describe ____

The undersigned owner or authorized representative*** of ____ is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility.

Ken Kisida

Signature, Owner or Authorized Representative
(Notarization is mandatory)

Utilities Manager - Ken Kisida
Typed Name and Title

Physical Plant Division - Building 702 Room 110
Address

Gainesville, Florida 32611
City State Zip

July 8, 1987
Date

904-392-1157
Telephone No.

*During actual time of operation.

**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-lbs/hr.

***Attach letter of authorization if not previously submitted

DER Form 17-1.202(4)
Effective November 30, 1982

Josephine E. Fidele
7/8/87

Notary Public, State of Florida
My Commission Expires June 17, 1988
Bonded Thru Troy Fain - Insurance, Inc.

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

PERMITTEE:

Mr. Ken Kisida, Utilities Manager
University of Florida
Physical Plant Division
Building 702, Room 110
Gainesville, Florida 32611

I.D. Number: 31GVL01001415
Permit/Cert Number: A001-136571
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992
County: Alachua
Lat/Long: 29°38'24"N/82°20'52"W
Section/Township/Range:
Project: No. 5 Steam Boiler at CHP
UTM: E-(17)369.5; N-3279.4

This permit is issued under the provisions of Chapter 403, Florida Statutes, and Florida Administrative Code Rule(s) 17-2 and 17-4. The above named permittee is hereby authorized to perform the work or operate the facility shown on the application and approved drawing(s), plans, and other documents attached hereto or on file with the department and made a part hereof and specifically described as follows:

For the operation of No.5 Steam Boiler at the Central Heal Plant (CHP).

Located west of Center Drive, north of Mowery Road, University of Florida, Gainesville, Alachua County, Florida.

In accordance with operating permit application dated August 23, 1977, renewal application dated June 21, 1982, renewal application dated July 8, 1987 and BACT Determination received September 24, 1987.

PERMITTEE:

University of Florida
No. 5 Steam Boiler at CHP

I.D. Number: 31GVL01001415
Permit Number: A001-1136571
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

GENERAL CONDITIONS:

1. The terms, conditions, requirements, limitations, and restrictions set forth herein are "Permit Conditions" and as such are binding upon the permittee and enforceable pursuant to the authority of Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is hereby placed on notice that the department will review this permit periodically and may initiate enforcement action for any violation of the "Permit Conditions" by the permittee, its agents, employees, servants, or representatives.

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), Florida Statutes, the issuance of this permit does not convey any vested rights or any exclusive privileges. Nor 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 does not constitute 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, plant or aquatic life or property and penalties therefore caused by the construction or operation of this permitted source, nor does it allow the permittee to cause pollution in contravention of Florida Statutes and department rules, unless specifically authorized by an order from the department.

6. The permittee shall at all times 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, access to the premises, at reasonable times, where the permitted activity is located or conducted for the purpose of:

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

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

c. Sampling or monitoring 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 notify and provide the department with the following information:

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

   b. the period of non-compliance, including exact 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 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 arising under the Florida Statutes or department rules, except where such use is proscribed by Sections 403.73 and 403.111, Florida Statutes.

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

11. This permit is transferable only upon department approval in accordance with Florida Administrative Code Rules 17-4.12 and 17-30.30, as applicable. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the department.

12. This permit is required to be kept at the work site of the permitted activity during the entire period of construction or operation.

PERMITTEE:

University of Florida
No. 5 Steam Boiler at CHP

I.D. Number: 31GVL01001415
Permit Number: A001-136571
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

13. This permit also constitutes:

( ) Determination of Best Available Control Technology (BACT)
( ) Determination of Prevention of Significant Deterioration (PSD)
( ) Certification of Compliance with State Water Quality Standards
( ) (Section 401, PL 92-500)
( ) Compliance with New Source Performance Standards

14. The permittee shall comply with the following monitoring and record keeping requirements:

a. Upon request, the permittee shall furnish all records and plans required under department rules. The retention period for all records will be extended automatically, unless otherwise stipulated by the department, during the course of any unresolved enforcement action.

b. The permittee shall retain 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), copies of all reports required by this permit, and records of all data used to complete the application for this permit. The time period of retention shall be 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 date(s) 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 period of time furnish any information required by law which is needed to determine compliance with the permit. If the permittee 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 submitted or corrected promptly.

PERMITTEE:

University of Florida
No. 5 Steam Boiler at CHP

I.D. Number: 31GVL01001415
Permit Number: A001-136571
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

SPECIFIC CONDITIONS:

1. The maximum input rate (operating rate) is 164,000 cf/hr of natural gas or 1066.6 gals/hr of No. 6 fuel oil and shall not be exceeded without prior approval.

2. Testing of emissions must be performed at an operating rate of at least 90% of the rate in Specific Condition (SC) No. 1, or SC No. 3 will become effective.

3. The operating rate shall not exceed 110% of the operating rate during the most recent test except for testing purposes, but shall not exceed the rate in SC No. 1. After testing at an operating rate greater than 110% of the last test operating rate, the operating rate shall not exceed 110% of the last (submitted) test operating rate until the test report at the higher rate has been reviewed and accepted by the Department.

4. The permitted maximum allowable emission rate for each pollutant is as follows:

Pollutant	Regulation	Emission Rate lbs/hr	Emission Rate TPY
Particulate Matter (PM)	17-2.600(6)(b), FAC	19.20[1]	76.80
Sulfur Dioxide (SO_2)	17-2.600(6)(c), FAC	265.58[2]	1062.33
Visible Emissions (VE)	17-2.600(6)(a), FAC	20% opacity, except 40% for 2 mins/hr[4]	

[1]Basis: 1066.6[3] gals/hr; 1.5%[4] S in FO; AP-42 emission factor

[2]Basis: 1066.6[3] gals/hr; 1.5%[4] S in FO; 8.3[3] lbs/gal

[3]Basis: 08-23-77 application

[4]Basis: BACT determination dated September 21, 1987 which limits the fuel fired to "new" No. 6 fuel oil (FO) with a sulfur content not to exceed 1.5% by weight. "New" means oil refined from crude oil and has not been used.

5. Test the emission for the following pollutant(s) at the interval(s) indicated, notify GBO office* fourteen (14) days prior to testing, and submit the test report documentations to GBO office* within 45 days after completion of the testing:

Pollutant	Interval from 01-20-87
SO_2	12 months; Send certified fuel oil analysis with the annual opn rpt if this unit is fired with No. 6 oil for more than 400 hours the previous calendar year.

* GBO at 5700 S.W. 34th Street, Suite 1204, Gainesville, Florida 32608
Phone No. (904)377-7528

PERMITTEE:

University of Florida
No. 5 Steam Boiler at CHP

I.D. Number: 31GVL01001415
Permit Number: A001-136571
Date of Issue: October 1, 1987
Expiration Date: August 1, 1992

CONDITIONAL VE BASED ON FUEL USED

Pollutant	Interval from 01-20-87
VE	12 months [1,2,3]

[1]Basis: Rule 17-2.700(2)(a)4., FAC - test annually unless otherwise specified

[2]Basis: Rule 17-2.700(2)(a)3., FAC - test not required when liquid fuel is burned for a total of no more than 400 hours

[3]Basis: If this unit was fired only with natural gas during the previous calendar year, so state in the annual operation report

Tests and test reports shall comply with the requirements of FAC Rule 17-2.700(6) and (7), respectively.

6. In each test report, submit the maximum input/production rate at which this source was operated since the most recent test.

7. Submit an annual operation report for this source on the form supplied by the Department for each calendar year on or before March 1.

8. Any revision(s) to a permit (and application) must be submitted and approved prior to implementing.

9. Forms for the renewal will be sent five (5) months prior to August 1, 1992 and the completed forms with test results are due 90 days prior to August 1, 1992 .

Issued this 1st day of October 1987

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL REGULATION

Ernest E. Frey

Ernest E. Frey, District Manager

Best Available Control Technology (BACT) Determination
University of Florida
Alachua County

The applicant plans to operate five boilers (Heat Plant No. 2) located at their facility in Gainesville, Florida. The five boilers which will be fired on a rotating basis with a maximum of three boilers operating simultaneously are capable of firing either natural gas or No. 6 fuel oil.

A BACT determination is required for the source as set forth in the Florida Administrative Code Rule 17-2.600 (6) - Emissions Limiting and Performance Standards.

<u>BACT Determination Request by the Applicant</u>:

Particulate and sulfur dioxide emissions to be controlled by the firing of natural gas or by firing No. 6 fuel oil containing 2.0 percent sulfur, by weight.

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

July 17, 1987

<u>Review Group Members</u>:

The determination was based upon comments received from the Stationary Source Control Section and the Northeast District.

<u>Review Determined by DER</u>:

The amount of particulate and sulfur dioxide emissions from the boilers will be limited by the firing of natural gas or firing new [1] No. 6 fuel oil having a sulfur content not to exceed 1.5 percent, by weight.

Visible Emissions : Not to exceed 20% opacity. 40% opacity is permitted for not more than two minutes in any one hour.

DER Method 9 (17-2.700(6)(a)9, FAC) will be used to determine compliance with the opacity standard.

[1] The term "new" means an oil which has been refined from crude oil and has not been used.

<u>BACT Determination Rationale</u>:

Sulfur in fuel oil is a primary air pollution concern in that most of the fuel sulfur becomes SO_2. The emission factors for SO_2 and particulate emissions from oil burning are related to

the sulfur content. The emission factors used by the applicant and the Department are from AP-42, Table 1.3-1.

The applicant has stated that the maximum steam load would require approximately 44 percent of the combined boiler capacity. At this level of operation, dispersion modeling indicates that the ambient air quality standards (AAQS) would not be exceeded for either particulates or sulfur dioxide. There is also no exceedances of the PSD increment since the boilers were each installed prior to the baseline date of December 27, 1977, and therefore do not consume increment.

Although the air quality impacts analysis does not indicate exceedances of the standards when firing the proposed 2.0% sulfur fuel oil, the economic impact of using lower sulfur content fuels needs to be addressed. A review of previous BACT determinations for boilers of similar size which fire No. 6 fuel oil indicates that the sulfur content has generally been limited to 1.5%.

In accordance with the 1.5% sulfur content limitation which is generally required for this type of boiler, the cost of fuel switching can be determined. The applicant has a contract rate of $20.65 per barrel for 2.0 percent No. 6 fuel oil. At the contract rate, No. 6 fuel oil with a sulfur content not to exceed 1.5 percent would cost $21.15 which corresponds to an additional 1.19 cents per gallon.

Assuming the maximum firing rate of 25 percent of total annual, capacity , the additional annual cost of using the 1.5% sulfur content fuel oil instead of the proposed 2.0% sulfur content No. 6 fuel oil would be $97,129. The sulfur dioxide reductions from switching to the 1.5% sulfur fuel oil are estimated to be 313.5 tons per year. Based on this reduction, the annual cost per ton of sulfur dioxide removed is approximately $310.00 which is less than the EPA guideline of up to $2,000 per ton for sulfur dioxide removal.

Based on the information presented in this analysis, the Bureau has determined that BACT is represented by the firing of either natural gas or No. 6 fuel oil with a sulfur content not to exceed 1.5 percent, by weight.

the sulfur content. The emission factors used by the applicant and the Department are from AP-42, Table 1.3-1.

The applicant has stated that the maximum steam load would require approximately 44 percent of the combined boiler capacity. At this level of operation, dispersion modeling indicates that the ambient air quality standards (AAQS) would not be exceeded for either particulates or sulfur dioxide. There is also no exceedances of the PSD increment since the boilers were each installed prior to the baseline date of December 27, 1977, and therefore do not consume increment.

Although the air quality impacts analysis does not indicate exceedances of the standards when firing the proposed 2.0% sulfur fuel oil, the economic impact of using lower sulfur content fuels needs to be addressed. A review of previous BACT determinations for boilers of similar size which fire No. 6 fuel oil indicates that the sulfur content has generally been limited to 1.5%.

In accordance with the 1.5% sulfur content limitation which is generally required for this type of boiler, the cost of fuel switching can be determined. The applicant has a contract rate of $20.65 per barrel for 2.0 percent No. 6 fuel oil. At the contract rate, No. 6 fuel oil with a sulfur content not to exceed 1.5 percent would cost $21.15 which corresponds to an additional 1.19 cents per gallon.

Assuming the maximum firing rate of 25 percent of total annual capacity , the additional annual cost of using the 1.5% sulfur content fuel oil instead of the proposed 2.0% sulfur content No. 6 fuel oil would be $97,129. The sulfur dioxide reductions from switching to the 1.5% sulfur fuel oil are estimated to be 313.5 tons per year. Based on this reduction, the annual cost per ton of sulfur dioxide removed is approximately $310.00 which is less than the EPA guideline of up to $2,000 per ton for sulfur dioxide removal.

Based on the information presented in this analysis, the Bureau has determined that BACT is represented by the firing of either natural gas or No. 6 fuel oil with a sulfur content not to exceed 1.5 percent, by weight.

Details of the Analysis May be Obtained by Contacting:

Barry Andrews, P.E. BACT Coordinator
Department of Environmental Regulation
Bureau of Air Quality Management
2600 Blairstone Road
Tallahassee, Florida 32399-2400

Recommended by:

C. H. Fancy, P.E.
Deputy Bureau Chief, BAQM

9/16/87
Date

Approved by:

Dale Twachtmann, Secretary

21 Sept 87
Date

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STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT RECEIVED J 9 1987 DER-JACKSONVILLE

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
(904) 396-6959

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

ERNEST E. FREY
DISTRICT MANAGER

APPLICATION FOR RENEWAL OF PERMIT TO OPERATE AIR POLLUTION SOURCE(S)

If major alterations have occurred, the applicant should complete the Standard Air Permit Application Form.

Source Type: No. 5 Steam Boiler Renewal of DER Permit No. A001-57683

Company Name: UNIVERSITY OF FLORIDA 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):

Black Steel Stack North End of Plant No. 5 Steam Boiler

Source Location: Street: Bldg 473 North of Mowery Road City: Gainesville

UTM: East ________ North ________

Latitude: __ __° __ __' __ __"N. Longitude: __ __° __ __' __ __"W.

---

1. Attach a check made payable to the Department of Environmental Regulation in accordance with operation permit fee schedule set forth in Florida Administrative Code Rule 17-4.05.

2. Have there been any alterations to the plant since last permitted? [ ] Yes [✓] No If minor alterations have occurred, describe on a separate sheet and attach.

3. Attach the last compliance test report required per permit conditions if not submitted previously.

4. Have previous permit conditions been adhered to? [✓] Yes [ ] No If no, explain on a separate sheet and attach.

5. Has there been any malfunction of the pollution control equipment during tenure of current permit? [ ] Yes [✓] No If yes, and not previously reported, give brief details and what action was taken on a separate sheet and attach.

6. Has the pollution control equipment been maintained to preserve the collection efficiency last permitted by the Department? [✓] Yes [ ] No

7. Has the annual operating report for the last calendar year been submitted? [ ] Yes [✓] No If no, please attach.

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8. Please provide the following information if applicable:

A. Raw Materials and Chemical Used in Your Process:

Description	Contaminant Type	%Wt	Utilization Rate lbs/hr

B. Product Weight (lbs/hr): 120,000

C. Fuels No. 6 Oil

Type (Be Specific)	Consumption* Avg/hr*	Max/hr**	Maximum Heat Input (MMBTU/hr)
No. 6 Fuel Oil		600 GALS	149,000 BTU per GAL, Min.

= 88 mmBtu/hr

D. Normal Equipment Operating Time: hrs/day 24; days/wk ____; wks/yr ____;

hrs/yr (power plants only) ____; if seasonal, describe ____

The undersigned owner or authorized representative*** of ____ is fully aware that the statements made in this application for a renewal of a permit to operate an air pollution source are true, correct and complete to the best of his knowledge and belief. Further, the undersigned agrees to maintain and operate the pollution source and pollution control facilities in such a manner as to comply with the provisions of Chapter 403, Florida Statutes, and all the rules and regulations of the Department. He also understands that a permit, if granted by the Department, will be non-transferable and he will promptly notify the Department upon sale or legal transfer of the permitted facility.

*During actual time of operation.

**Units: Natural Gas-MMCF/hr; Fuel Oils-barrels/hr; Coal-lbs/hr.

***Attach letter of authorization if not previously submitted

Ken Kisida

Signature, Owner or Authorized Representative (Notarization is mandatory)

Utilities Manager - Ken Kisida

Typed Name and Title

Physical Plant Division - Building 702 Room 110

Address

Gainesville, Florida 32611

City State Zip

July 8, 1987

Date

904-392-1157

Telephone No.

Notary Public, State of Florida

My Commission Expires June 17, 1989

Bonded Thru Troy Fain - Insurance, Inc.

Josephine E. Tisdale

7/8/87

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 88 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 1 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida; Physical Plant Div.; Bldg. 473
   Gainesville, Fl 32611
4. Description of Source: Black steel stack south end of Plant

II ACTUAL OPERATING HOURS: 1923.5 hrs/day ________ days/wk ________ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

91372.0 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

N/A 10^3 gallons ________ Oil, ________ %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

________ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

________ TYPED NAME AND TITLE

________ DATE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

DEPARTMENT OF ENVIRONMENTAL REGULATION
STATE OF FLORIDA

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1988 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 2 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div.; Bldg 473;
   Gainesville, Fl. 32611
4. Description of Source: Black steel stack second from south end of Plant

II ACTUAL OPERATING HOURS: 2892.0 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

84753.0 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

N/A 10^3 gallons ________ Oil, ________ %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________________________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________________________________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

________________________________ ________________________________

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE TYPED NAME AND TITLE

____

DATE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1988 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 3 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div.; Bldg 473
   Gainesville, Fl 32611
4. Description of Source: ________

II ACTUAL OPERATING HOURS: 4451.6 hrs/day ____ days/wk ____ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 120,000 lbs per hour

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

464,100	10^6 cubic feet Natural Gas	________	10^3 Kerosene
26,268	10^3 gallons 6 Oil, 2 %S	________	tons Coal
________	10^3 gallons Propane	________	tons Carbonaceous
________	10^6 Black Liquor Solids	________	tons Refuse

Other (Specify type and units) ____________________

VI EMISSION RATE(S) (tons/yr)

________	Particulates	________	Sulfur Dioxide	________	Total Reduced Sulfur
________	Nitrogen Oxide	________	Carbon Monoxide	________	Fluoride
________	Hydrocarbon				

Other (Specify type and units) ____________________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. The highest six-min. average was 4.3 percent.

II CERTIFICATION:

hereby certify that the information given in this report is correct to the best of my owledge.

____________________ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

____________________ TYPED NAME AND TITLE

____________________ DATE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1988 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 4 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div.; Bldg 473
   Gainesville
4. Description of Source: Black steel stack second from North end.

II ACTUAL OPERATING HOURS: 3992.1 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 50,000 lbs per hour

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T[redacted]AL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

1[redacted].651 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

40.772 10^3 gallons 6 Oil, 2 %S ________ tons Coal

[redacted] 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

O[redacted]her (Specify type and units) ________________________

EMISSION RATE(S) (tons/yr)

[redacted] Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

[redacted] Hydrocarbon Other (Specify type and units) ________________________

METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, [redacted]ission factors drawn from AP 42, etc.)

[redacted]A method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. The highest six-min. average was .05 percent.

I CERTIFICATION:

er[redacted]y certify that the information given in this report is correct to the best of my wl[redacted]ge.

________________________ ________________________

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

TYPED NAME AND TITLE

____

DATE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1988 prior to March 1st of the following year.

I **GENERAL INFORMATION**

1. Source Name: No. 5 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida; Physical Plant Div. Bldg 473
   Gainesville, Fl 32611
4. Description of Source: Black steel stack on North end of Plant

II **ACTUAL OPERATING HOURS:** 6411 hrs/day ____ days/wk ____ wks/yr

III **RAW MATERIAL INPUT PROCESS WEIGHT:** (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV **PRODUCT OUTPUT** (Specify applicable units)

Steam at 120,000 lbs per hour

V **TOTAL FUEL USAGE** including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

537.777 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

537.506 10^3 gallons 6 Oil, 2 %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________________________

VI **EMISSION RATE(S)** (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________________________________

VII **METHOD OF CALCULATING EMISSION RATES** (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. The highest six-min. average was 9.7 percent.

VIII **CERTIFICATION:**

I hereby certify that the information given in this report is correct to the best of my knowledge.

________________________________ ________________________________

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE — TYPED NAME AND TITLE

____

DATE

DER Form #
Form Title
Effective Date
DER Application No.

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1989 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 1 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida; Physical Plant Div.; Bldg 473
   Gainesville, Fl 32611
4. Description of Source: Black steel stack, south end of Plant

II ACTUAL OPERATING HOURS: 3989.0 hrs/day ____ days/wk ____ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

Northwest District 160 Governmental Center Pensacola, Florida 32501-5794 904-436-8300
Northeast District 3426 Bills Rd Jacksonville, Florida 32207 904-798-4200
Central District 3319 Maguire Blvd Suite 232 Orlando, Florida 32803-3767 407-894-7555
Southwest District 4520 Oak Fair Blvd Tampa, Florida 33610-7347 813-623-5561
South District 2269 Bay St Fort Myers, Florida 33901-2896 813-332-2667
Southeast District 1900 S Congress Ave Suite A West Palm Beach, Florida 33406 407-964-9668

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

158,848.0 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

N/A 10^3 gallons ________ Oil, ________ %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

________________ ________________

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE TYPED NAME AND TITLE

____

DATE

DER Form #
Form Title
Effective Date
DER Application No.

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1989 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 2 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div.; Bldg 473
   Gainesville, Fl 32611
4. Description of Source: Black steel stack second from south end of plant

II ACTUAL OPERATING HOURS: 3125.8 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

144,723.0 10^6 cubic feet Natural Gas ______ 10^3 Kerosene

N/A 10^3 gallons ______ Oil, ______ %S ______ tons Coal

______ 10^3 gallons Propane ______ tons Carbonaceous

______ 10^6 Black Liquor Solids ______ tons Refuse

Other (Specify type and units) ______

VI EMISSION RATE(S) (tons/yr)

______ Particulates ______ Sulfur Dioxide ______ Total Reduced Sulfur

______ Nitrogen Oxide ______ Carbon Monoxide ______ Fluoride

______ Hydrocarbon Other (Specify type and units) ______

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

______ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

______ TYPED NAME AND TITLE

______ DATE

DER Form #
Form Title
Effective Date
DER Application No.

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1989 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 3 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div. Bldg 473
   Gainesville, Fl 32611
4. Description of Source: ____

II ACTUAL OPERATING HOURS: 5057.2 hrs/day ____ days/wk ____ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 120,000 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

Northwest District 160 Governmental Center Pensacola, Florida 32501-5794 904-436-8300
Northeast District 3426 Bills Rd Jacksonville, Florida 32207 904-798-4200
Central District 3319 Maguire Blvd, Suite 232 Orlando, Florida 32803-3767 407-894-7555
Southwest District 4520 Oak Fair Blvd Tampa, Florida 33610-7347 813-623-5561
South District 2269 Bay St Fort Myers, Florida 33901-2896 813-332-2667
Southeast District 1900 S Congress Ave, Suite A West Palm Beach, Florida 3340 407-964-9666

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

392,375.0	10^6 cubic feet Natural Gas	________	10^3 Kerosene
11,269	10^3 gallons 6 Oil, 2 1.5 %S	________	tons Coal
________	10^3 gallons Propane	________	tons Carbonaceous
________	10^6 Black Liquor Solids	________	tons Refuse

Other (Specify type and units) ________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. The highest six-minute average was 6.0 percent.

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

________________________ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

________________________ TYPED NAME AND TITLE

________________________ DATE

Florida Department of Environmental Regulation

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

DER Form #
Form Title
Effective Date
DER Application No.

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1989 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 4 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div. Bldg 473
   Gainesville, Fl 32611
4. Description of Source: Black steel stack second from North end.

II ACTUAL OPERATING HOURS: 2035.9 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 50,000 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

76,466.7	10^6 cubic feet Natural Gas		10^3 Kerosene
123,978.9	10^3 gallons 6 Oil, 2.5 %S		tons Coal
	10^3 gallons Propane		tons Carbonaceous
	10^6 Black Liquor Solids		tons Refuse

Other (Specify type and units) ______

VI EMISSION RATE(S) (tons/yr)

______ Particulates ______ Sulfur Dioxide ______ Total Reduced Sulfur

______ Nitrogen Oxide ______ Carbon Monoxide ______ Fluoride

______ Hydrocarbon Other (Specify type and units) ______

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. The highest six-minute was 1.0 percent.

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

______ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

______ TYPED NAME AND TITLE

______ DATE

DER Form #
Form Title
Effective Date
DER Application No.

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1989 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 5 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida; Physical Plant Div. Bldg 473
   Gainesville, Fl 32611
4. Description of Source: Black Steel stack on North end of Plant

II ACTUAL OPERATING HOURS: 4549.9 hrs/day ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 120,000 lbs per hour

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

403.204.6	10^6 cubic feet Natural Gas	____	10^3 Kerosene
28.481	10^3 gallons 6 Oil, 1.5 %S	____	tons Coal
____	10^3 gallons Propane	____	tons Carbonaceous
____	10^6 Black Liquor Solids	____	tons Refuse

Other (Specify type and units) ____

VI EMISSION RATE(S) (tons/yr)

____ Particulates ____ Sulfur Dioxide ____ Total Reduced Sulfur

____ Nitrogen Oxide ____ Carbon Monoxide ____ Fluoride

____ Hydrocarbon Other (Specify type and units) ____

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. The highest six-minute average was 5.2 percent.

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

____ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

____ TYPED NAME AND TITLE

____ DATE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 90 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 1 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida; Physical Plant Div; Bldg. 473
   Gainesville, Fl 32611
4. Description of Source: Black steel stack, south end of plant

II ACTUAL OPERATING HOURS: 809.4 hrs/~~day~~ ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,00 lbs per hour

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

20,523 10^6 cubic feet Natural Gas

______ 10^3 Kerosene

N/A 10^3 gallons ______ Oil, ______ %S

______ tons Coal

______ 10^3 gallons Propane

______ tons Carbonaceous

______ 10^6 Black Liquor Solids

______ tons Refusé

Other (Specify type and units) ______

VI EMISSION RATE(S) (tons/yr)

______ Particulates ______ Sulfur Dioxide ______ Total Reduced Sulfur

______ Nitrogen Oxide ______ Carbon Monoxide ______ Fluoride

______ Hydrocarbon Other (Specify type and units) ______

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

______ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

______ TYPED NAME AND TITLE

______ DATE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1990 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 2 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida; Physical Plant Div; Bldg. 473
   Gainesville, Fl. 32611
4. Description of Source: Black steel stack second from south end of plant

II ACTUAL OPERATING HOURS: 3440.0 hrs/~~day~~XX ____ days/wk ____ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 60,000 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

V TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

124.076 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

N/A 10^3 gallons ________ Oil, ________ %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________________________

VI EMISSION RATE(S) (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________________________

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

N/A

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

________________________ ________________________

SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE TYPED NAME AND TITLE

____

DATE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1990 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 3 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div. Bldg. 473
   Gainesville, Fl. 32611
4. Description of Source: Black steel stack center of plant

II ACTUAL OPERATING HOURS: 2648.1 hrs/~~day~~ ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 120,00 lbs per hour

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

248.350 10^6 cubic feet Natural Gas ______ 10^3 Kerosene

0.019 10^3 gallons 6 Oil, 1.5 %S ______ tons Coal

______ 10^3 gallons Propane ______ tons Carbonaceous

______ 10^6 Black Liquor Solids ______ tons Refuse

Other (Specify type and units) ______

VI EMISSION RATE(S) (tons/yr)

______ Particulates ______ Sulfur Dioxide ______ Total Reduced Sulfur

______ Nitrogen Oxide ______ Carbon Monoxide ______ Fluoride

______ Hydrocarbon Other (Specify type and units) ______

VII METHOD OF CALCULATING EMISSION RATES (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. The highest six-minute average was 6.0 percent.

VIII CERTIFICATION:

I hereby certify that the information given in this report is correct to the best of my knowledge.

______
SIGNATURE OF OWNER OR
AUTHORIZED REPRESENTATIVE

______
TYPED NAME AND TITLE

______
DATE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 19 90 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: NO. 4 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida, Physical Plant Div. Bldg. 473
   Gainesville Fl. 32611
4. Description of Source: Black steel stack second from North end of plant

II ACTUAL OPERATING HOURS: 4739.2 hrs/~~day~~ ______ days/wk ______ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 50,000 lbs per hour

DER Form 17-1.202(6)
Effective November 30, 1982

TOTAL FUEL USAGE including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

210.507	10^6 cubic feet Natural Gas		10^3 Kerosene
0.870	10^3 gallons 6 Oil, 1.5 %S		tons Coal
	10^3 gallons Propane		tons Carbonaceous
	10^6 Black Liquor Solids		tons Refuse

Other (Specify type and units) ______

VI **EMISSION RATE(S)** (tons/yr)

	Particulates		Sulfur Dioxide		Total Reduced Sulfur
	Nitrogen Oxide		Carbon Monoxide		Fluoride
	Hydrocarbon				

Other (Specify type and units) ______

VII **METHOD OF CALCULATING EMISSION RATES** (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacticy. The highest six-minute was 1.0 percent.

VIII **CERTIFICATION:**

I hereby certify that the information given in this report is correct to the best of my knowledge.

______ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

______ TYPED NAME AND TITLE

______ DATE

STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL REGULATION

NORTHEAST DISTRICT
3426 BILLS ROAD
JACKSONVILLE, FLORIDA 32207
904/798-4200

BOB MARTINEZ
GOVERNOR
DALE TWACHTMANN
SECRETARY
ERNEST E. FREY
DISTRICT MANAGER
GARY L. SHAFFER
ASSISTANT DISTRICT MANAGER

ANNUAL OPERATION REPORT FORM FOR AIR EMISSIONS SOURCES

For each permitted emission point, please submit a separate report for calendar year 1990 prior to March 1st of the following year.

I GENERAL INFORMATION

1. Source Name: No. 5 Steam Boiler
2. Permit Number: A001-57683
3. Source Address: Univ. of Florida; Physical plant Div. Bldg. 473
   Gainesville, Fl. 32611
4. Description of Source: Black steel stack on North end of plant

II ACTUAL OPERATING HOURS: 5115.6 hrs/~~day~~ ____ days/wk ____ wks/yr

III RAW MATERIAL INPUT PROCESS WEIGHT: (List separately all materials put into process and specify applicable units if other than tons/yr)

Raw Material	Input Process Weight
	tons/yr
	tons/yr
	tons/yr
	tons/yr
	tons/yr

IV PRODUCT OUTPUT (Specify applicable units)

Steam at 120,000 lbs. per hour

V **TOTAL FUEL USAGE** including standby fuels. If fuel is oil, specify type and sulfur content (e.g., No. 6 oil with 1% S).

416.845 10^6 cubic feet Natural Gas ________ 10^3 Kerosene

5.557 10^3 gallons 6 Oil, 1.5 %S ________ tons Coal

________ 10^3 gallons Propane ________ tons Carbonaceous

________ 10^6 Black Liquor Solids ________ tons Refuse

Other (Specify type and units) ________

VI **EMISSION RATE(S)** (tons/yr)

________ Particulates ________ Sulfur Dioxide ________ Total Reduced Sulfur

________ Nitrogen Oxide ________ Carbon Monoxide ________ Fluoride

________ Hydrocarbon Other (Specify type and units) ________

VII **METHOD OF CALCULATING EMISSION RATES** (e.g., use of fuel and materials balance, emission factors drawn from AP 42, etc.)

EPA method 9 was used as described in 40 cfr 60, appendix A. The visible emission limit is 20 percent opacity. the highest six-minute average was 5.2 percent.

VIII **CERTIFICATION:**

I hereby certify that the information given in this report is correct to the best of my knowledge.

________ SIGNATURE OF OWNER OR AUTHORIZED REPRESENTATIVE

________ TYPED NAME AND TITLE

________ DATE

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. Scott H. Osbourn
Senior Environmental Engineer
Florida Power Corporation
3201 Thirty-fourth Street South
St. Petersburg, Florida 33733

4a. Article Number
Z 127 632 515

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

7. Date of Delivery 5/14/95

5. Signature (Addressee) M. Williams

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 127 632 515

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

UNITED STATES POSTAL SERVICE

Sent to: Mr. Scott H. Osbourn	
Street and No.: Senior Environmental Eng	
P.O., State and ZIP Code: 3201 34th St. S St Petersburg FL 33733	
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: AC01-204652 AC49-203114 Title V extension	

PS Form **3800**, March 1993

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. W. Jeffrey Pardue Director
Environmental Service Dept.
Fla. Power Corp.
PO Box 14042
St. Pete, Fl 33733

4a. Article Number
Z 311 902 897

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

7. Date of Delivery MAY 30 1995

5. Signature (Addressee) M. Williams

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 311 902 897

UNITED STATES POSTAL SERVICE

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

PS Form 3800, March 1993

Sent to Jeffrey Pardue	
Street and No. Fla Power Corp	
P.O., State and ZIP Code St. Pete, 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	5-26-95

4C01-204652
PSD-Fl-181

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. W. Jeffrey Parude, C.E.P.
Florida Power Corporation
P. O. Box 14042
St. Petersburg, Florida 33733

4a. Article Number
P 872 562 687

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

7. Date of Delivery
DEC 9 1994

5. Signature (Addressee)
Brian Williams

6. Signature (Agent)

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

Thank you for using Return Receipt Service.

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

P 872 562 687

UNITED STATES POSTAL SERVICE

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

Sent to	Mr. W. Jeffrey Pardue
Street and No.	P. O. Box 14042
P.O., State and ZIP Code	St. Petersburg, FL 33733
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: 12/07/94 AC01-204652, PSD-FL-181

PS Form 3800, JUNE 1991

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.

RECEIVED
MAY 19 1994
Bureau of
Air Regulation

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. Scott H. Osbourn
Senior Environmental Engineer
Florida Power Corporation
P. O. Box 14042
St. Petersburg, Florida 33733

4a. Article Number
P 872 563 635

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

7. Date of Delivery
MAY 16 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 872 563 635

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

UNITED STATES POSTAL SERVICE

Sent to Mr. Scott Osbourn	
Street and No. P. O. Box 14042	
P.O., State and ZIP Code St. Petersburg, FL 33733	
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: 5/13/94 AC 01-204652, PSD-FL-181	

PS Form 3800, JUNE 1991

P 062 921 988

Receipt for Certified Mail

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

UNITED STATES POSTAL SERVICE

Sent to: Mr. R. W. Neiser, FPC	
Street and No.: 3201-34th Street South	
P.O., State and ZIP Code: St. Petersburg, FL 33733	
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: 8-17-92 Permit: AC 01-204652	

PS Form 3800, June 1991

Final

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 Fee will provide you the signature of the person delivered to and the date of delivery.

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. R. W. Neiser
Florida Power Corporation
3201-34th Street South
St. Petersburg, FL 33733

4a. Article Number: P 062 921 988

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

7. Date of Delivery: AUG 20 1992

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form 3811, November 1990 ☆U.S. GPO: 1991—287-066 **DOMESTIC RETURN RECEIPT**

P 710 058 543

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

UNITED STATES POSTAL SERVICE

Sent to Mr. R. W. Neiser, FPC	
Street & No. 3201-34th Street South	
P.O., State & ZIP Code St. Petersburg, FL 33733	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 7-6-92 Permit: AC 01-204652 PSD-FL-181	

PS Form 3800, June 1990

intent

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 next to the article number.

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. R. W. Neiser
Sr. Vice President-Legal and Gov. Affairs
Florida Power Corporation
3201-34th Street South
St. Petersburg, FL 33733

4a. Article Number
P 710 058 543

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

7. Date of Delivery JUL 8 1992

5. Signature (Addressee)

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

6. Signature (Agent)
Frank Chinn

PS Form 3811, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

Florida Power
CORPORATION

RECEIVED

JUN 18 1992

Division of Air
Resources Management

June 15, 1992

Mr. Richard Donelan, Esq.
Office of General Counsel
Florida Department of Environmental Regulation
2600 Blairstone Rd.
Tallahassee, Florida 32399-2400

Dear Mr. Donelan:

Re: Florida Power Corporation/University of Florida Cogeneration Project
Permit No. AC 01-204652, PSD-FL-181

On June 8, 1992, Florida Power Corporation (FPC) received the Technical Evaluation and Preliminary Determination and proposed air construction permit for the above referenced facility. A review of the permit conditions has revealed that several issues remain to be resolved. I have had conversations with Mr. Clair Fancy of FDER and he has agreed that an extention of time to discuss these issues is appropriate. Therefore, based upon Mr. Fancy's recommendation and pursuant to Section 17-120.070, FAC, FPC respectfully requests an extension of time in which to file a petition for an administrative hearing under Section 120.57 FS, up to and including June 24, 1992.

If you should have any questions, please contact Mr. Scott Osbourn at (813) 866-5158.

Sincerely,

W. Jeffrey Pardue, Manager
Environmental Programs

cc: C. Fancy, FDER-Tallahassee
J. Reynolds
C. Holladay
G. Kuttyna, NE Dist
CHF/PL

M.A.C. H2G
POST OFFICE BOX 14042, ST. PETERSBURG, FLORIDA 33733

SAINT PETERSBURG
JUN 16 '92
FLA.

U.S. POSTAGE
0.29
METER
6219977

Florida Power
CORPORATION

Mr. C. Fancy
Florida Department of Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

951 675(S)

P 710 058 538

Certified Mail Receipt

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

UNITED STATES POSTAL SERVICE

Sent to Mr. R. W. Neiser, FPC	
Street & No. 3201-34th St. South	
P.O., State & ZIP Code St. Petersburg, FL 33733	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 6-2-92 Permit: AC 01-204652 PSD-FL-181	

PS Form 3800, June 1990

P 832 538 764

Certified Mail Receipt

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Do not use for International Mail
(See Reverse)

UNITED STATES POSTAL SERVICE

Sent to Mr. R. W. Neiser, FPC	
Street & No. 3201-34th Street South	
P.O., State & ZIP Code St. Petersburg, FL 33733	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Oelivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$
Postmark or Date Mailed: 1-13-92 Permit: AC 01-204652 PSD-FL-181	

PS Form 3800, June 1990

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 next to the article number.

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. R. W. Neiser
Senior Vice President-Legal and Gov. Affairs
Florida Power Corporation
3201 - 34th Snreet South
St. Petersburg, FL 33733

4a. Article Number
P 832 538 764

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

7. Date of Delivery
JAN 16 1992

5. Signature (Addressee)

6. Signature (Agent)

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

PS Form 3811, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

Florida Department of Environmental Regulation
Northeast District • Suite B200, 7825 Baymeadows Way • Jacksonville, Florida 32256-7577
Lawton Chiles, Governor
Carol M. Browner, Secretary

January 7, 1992

Mr. Scott Osborn
Florida Power Corporation
Post Office Box 14042
St. Petersburg, Florida 33733

Alachua County - AP
Florida Power Corporation
Cogen Project at U of Fl.

Dear Mr. Osborn:

The applications for transfer of permits enclosed are being returned per the January 06 (Patty Adams and Johnny Cole) teleconference.

The $250.00 for the transfer fees is to be refunded under separate cover.

The cogen certificate is to address the transfer of permits issue.

If there are any questions, please contact Johnny Cole at the letterhead address/telephone number.

Sincerely,

Andrew G. Kutyna
Andrew G. Kutyna, P.E.
District Air Program
Administrator

AGK:JC:bt

cc: Patty Adams, DARM, BAR

Department of Environmental Regulation

Routing and Transmittal Slip

To: (Name, Office, Location)

1.	Patty Adams
2.	DARM BAR
3.	
4.	

Remarks:

RECEIVED
JAN 9 1992
Division of Air
Resources Management

From:	Date
Air / Jax	Phone

P 832 538 758

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

UNITED STATES POSTAL SERVICE

Sent to Mr. R. W. Neiser	
Street & No. Senior VP-Legal & Gov. Affairs FL Power Corp.	
P.O., State & ZIP Code 3201-34th Street South St. Petersburg, FL 33733	
Postage	$
Certified Fee	
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	
Return Receipt Showing to Whom, Date, & Address of Delivery	
TOTAL Postage & Fees	$
Postmark or Date mailed: 12/31/91 AC 01-204652 PSD-FL-181	

PS Form **3800**, June 1990

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 next to the article number.

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. R. W. Neiser
Senior V.P.-Legal & Gov. Affairs
Florida Power Corp.
3201-34th Street South
St. Petersburg, Florida 33733

4a. Article Number
P 832 538 758

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

7. Date of Delivery JAN 02 1992

5. Signature (Addressee)

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

6. Signature (Agent)
[signature]

PS Form **3811**, October 1990 ☆U.S. GPO: 1990—273-861 **DOMESTIC RETURN RECEIPT**

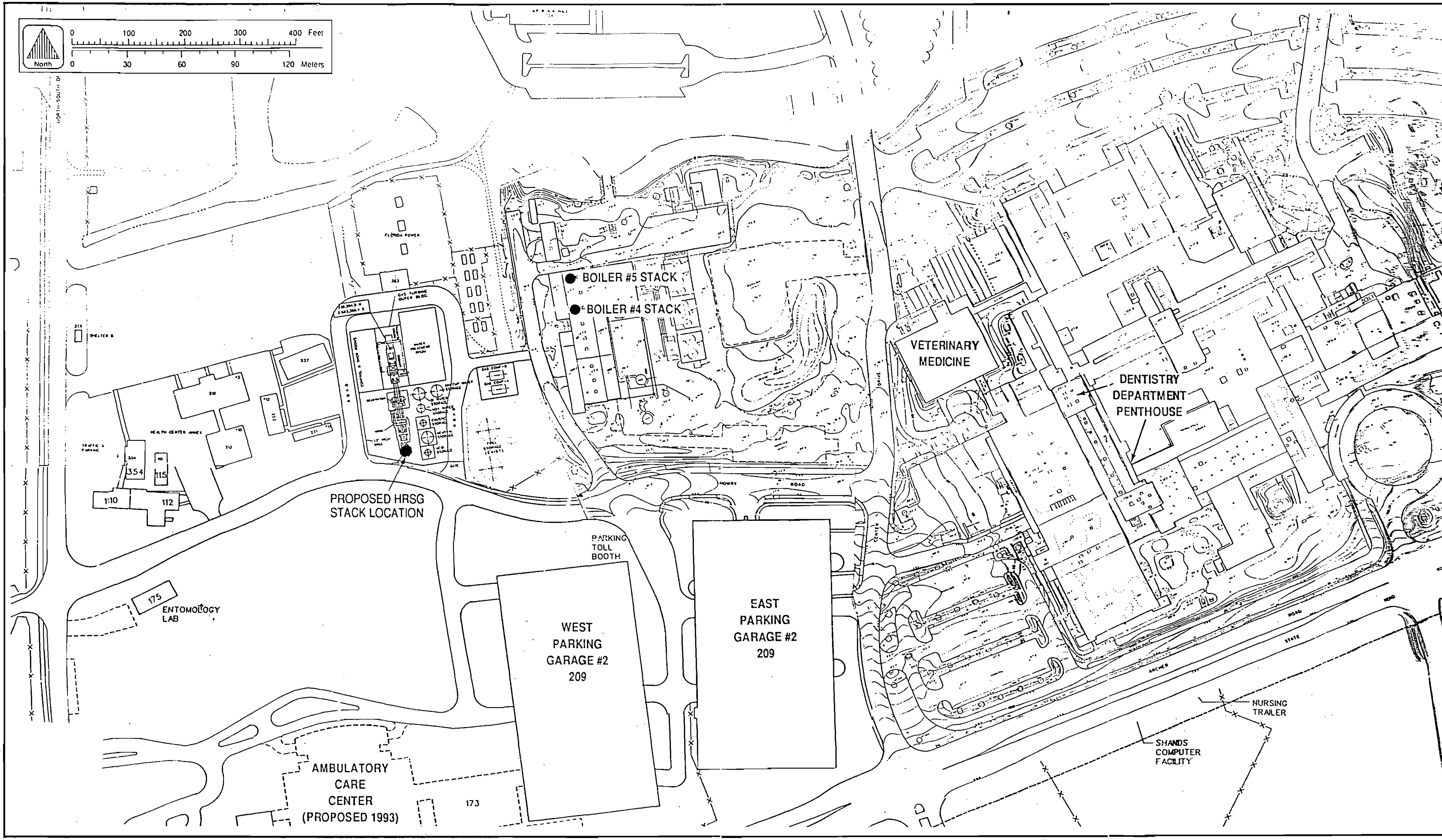

Figure 6-1 SITE AREA MAP INDICATING ALL BUILDING STRUCTURES CONSIDERED IN THE MODELING ANALYSIS

KBN

→PS/11

Check Sheet

Company Name: Florida Power Corp
Permit Number: AC-01-204652
PSD Number:
County: PSD 181
Permit Engineer:
Others involved:

Cross Reference:
AC 49-203114
PSD FL-180

Application:
- [x] Initial Application
- [x] Incompleteness Letters
- [x] Responses
- [ ] Final Application (if applicable)
- [ ] Waiver of Department Action
- [ ] Department Response
- [ ] Other

Intent:
- [x] Intent to Issue
- [x] Notice to Public
- [x] Technical Evaluation
- [x] BACT Determination
- [x] Unsigned Permit
- [ ] Correspondence with:
  - [x] EPA
  - [ ] Park Services
  - [ ] County
  - [ ] Other
- [x] Proof of Publication
- [ ] Petitions - (Related to extensions, hearings, etc.)
- [ ] Other

Final Determination:
- [x] Final Determination
- [x] Signed Permit
- [x] BACT Determination
- [ ] Other

Post Permit Correspondence:
- [ ] Extensions
- [ ] Amendments/Modifications
- [ ] Response from EPA
- [ ] Response from County
- [ ] Response from Park Services
- [x] Other

PSD-FL-181 PERMITTING HISTORY

Company Name: Florida Power Corporation **Facility ID No.: 0010001**
Plant Name: University of Florida Cogeneration Facility

PSD Permit History (for tracking purposes):

	Issue	**PERMITTING ACTION DESCRIPTION**
Permit No.	Date	
PSD-FL-181 AC01-204652	08/17/92	Permit to install/construct a 43 MW cogeneration facility
PSD-FL-181A	05/26/95	Amendment to incorporate the Custom Fuel Monitoring Schedule
PSD-FL-181	08/13/95	Extension of Expiration Date in accordance with Rule 62-213.420 F.A.C
PSD-DL-181B 0010001-002AC	03/18/97	Amendment to increase the maximum heat input to the CT without increasing the annual cap.

Appendix H-1, Permit History/ID Number Changes

Florida Power Corporation
University of Florida

FINAL Permit No.: 0010001-001-AV
Facility ID No. 0010001

Permit History (for tracking purposes):

E.U. ID No.	Description	Permit Nos.	Issue Date	Expiration Date[1, 2]	Extended Date[1, 2]	Revised Date(s)
-001	Cogeneration Gas Turbine	AC01-204652/ PSD-FL-181	08/17/92	12/31/94	11/01/96	03/18/97
-002	Boiler #4	AO01-214830	08/28/92	12/31/94	08/14/96	
-003	Boiler #5	AO01-214831	08/28/92	12/31/94	08/14/96	

(if applicable) ID Number Changes (for tracking purposes):

From: **Facility ID No.**: 31GVL010014

To: **Facility ID No.**: 0010001

Notes:
[1] - AO permit(s) automatic extension(s) in Rule 62-210.300(2)(a)3.a., F.A.C., effective 03/21/96.
[2] - AC permit(s) automatic extension(s) in Rule 62-213.420(1)(a)4., F.A.C., effective 03/20/96.
{Rule 62-213.420(1)(b)2., F.A.C., effective 03/20/96, allows Title V Sources to operate under existing valid permits that were in effect at the time of application until the Title V permit becomes effective.}

Detail | **Events** | **Facility** | **perMitted EU** | **Help** | **eXit**

Permitting Application

Permit #:**0010001-001-AV** PATS: Issue:**11-NOV-1999** Expire:**11-NOV-2004**

Project #/Name	Owner/Company	Type/Sub	Receive
001/FPC-U OF F COGENERATION	**FLORIDA POWER CORPORATION**	**AV /00**	**14-JUN-1996**
002/INCREASED FIRING RATE/NOX	FLORIDA POWER CORPORATION	AC /M1	31-MAR-1995
/UNIVERSITY OF FL COGENERA	FLORIDA POWER CORPORATION	AC /1B	13-NOV-1991
/#2 BOILER	FLORIDA POWER CORPORATION	AO /2B	15-JUN-1992
/#4 BOILER	FLORIDA POWER CORPORATION	AO /2B	15-JUN-1992
/#5 BOILER	FLORIDA POWER CORPORATION	AO /2B	15-JUN-1992
/U OF FL COGEN. (AC01-2046	FLORIDA POWER CORPORATION	AC /M1	05-APR-1995
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