Prevention of Significant Deterioration Permit Application

For

GRU

GAINESVILLE REGIONAL UTILITIES
Deerhaven Generating Station

COMBUSTION TURBINE ADDITION

GAINESVILLE REGIONAL UTILITIES 301SE 4th Avenue, Gainesville, Florida 32601

March 1994

Prepared By:

ENSERCH ENVIRONMENTAL
CORPORATION

Formerly the Environmental Division of Ebasco Services Incorporated
145 Technology Park, Norcross, Georgia 30092-2979

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March 22, 1994

RECEIVED
MAR 22 1994
Bureau of
Air Regulation

BY HAND DELIVERY

Mr. Clair Fancy
Bureau of Air Regulation
Department of Environmental Protection
Magnolia Courtyard, Room 127
Tallahassee, FL 32399

Re: Alachua County
City of Gainesville, Gainesville Regional Utilities
Deerhaven Combustion Turbine 3 Project

Dear Mr. Fancy:

Please find enclosed five copies of an application for a federally-required prevention of significant deterioration permit for a nominal 74 megawatt simple cycle combustion turbines to be located within Gainesville Regional Utilities Deerhaven power plant site. The Deerhaven site has been previously certified under the Florida Electrical Power Plant Siting Act. In addition to this application, a companion request for modification of site certification has also been submitted to the Department's Office of Siting Coordination. A fee of $10,000 has been paid to that Office to cover agency review expenses for this project. The computer printouts and computer disks of the air quality modeling results are being sent under separate cover directly to Tom Rogers of DEP.

I will be contacting your staff in a few weeks to review the initial comments your staff may have. In the meantime, please call either Yolanta Jonynas of GRU at (904) 334-3400, ext. 1284 or me if you have any questions.

Sincerely,

Douglas S Roberts

Douglas S. Roberts

DSR/gs

cc: Preston Lewis, DEP
Hamilton S. Oven, DEP
Doug Beck, GRU
Yolanta Jonynas, GRU
Doug Fulle, Ebasco

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

GAINESVILLE REGIONAL UTILITIES (GRU) DEERHAVEN GENERATING STATION COMBUSTION TURBINE ADDITION

Gainesville Regional Utilities
301 SE 4th Ave.
Gainesville, FL 32601

March 1994

Prepared by:
ENSERCH Environmental Corporation
formerly the Environmental Division of Ebasco Services Incorporated
145 Technology Park
Norcross, GA 30092

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

N TOWERS OFFICE BUILDING
0 BLAIR STONE ROAD
ALLAHASSEE, FLORIDA 32301

PSD-FL-212

BOB GRAHAM
GOVERNOR
VICTORIA J. TSCHINKEL
SECRETARY

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Combustion Turbine ☒ New[1] ☐ Existing[1]

APPLICATION TYPE: ☒ Construction ☐ Operation ☐ Modification

COMPANY NAME: City of Gainesville, Gainesville Regional Utilities **COUNTY:** Alachua

Identify the specific emission point source(s) addressed in this application (i.e. Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) COMBUSTION TURBINE DHCT-3 NAT. GAS/DISTILLATE FUEL Oil FIRED

SOURCE LOCATION: Street US 441/SR20/SR25 City Gainesville

UTM: East 365.5 km North 3292.7 km

Latitude 29 ° 45 ' 32 "N Longitude 82 ° 23 ' 26 "W

APPLICANT NAME AND TITLE: Michael L. Kurtz, General Manager for Utilities Gainesville Regional Utilities

APPLICANT ADDRESS: P. O. Box 147117, Station A-134, Gainesville, FL 32614-7117

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of Gainesville Regional Utilities

I certify that the statements made in this application for a Construction permit are true, correct and complete to the best of my knowledge and belief. Further, I agree to maintain and operate the pollution control source and pollution control facilities in such a manner as to comply with the provision of Chapter 403, Florida Statutes, and all the rules and regulations of the department and revisions thereof. I also understand that a permit, if granted by the department, will be non-transferable and I will promptly notify the department upon sale or legal transfer of the permitted establishment.

*Attach letter of authorization

Signed: Michael L. Kurtz

Michael L. Kurtz, General Manager for Utilities
Name and Title (Please Type)

Date: 3/08/94 Telephone No. (904) 334-3400 X1006

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.)

This is to certify that the engineering features of this pollution control project have been ~~designed/~~examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgment, that

---

[1] See Florida Administrative Code Rule 17-2.100(57) and (104)

the pollution control facilities, when properly maintained and operated, will dischar an effluent that complies with all applicable statutes of the State of Florida and the rules and regulations of the department. It is also agreed that the undersigned will furnish, if authorized by the owner, the applicant a set of instructions for the proper maintenance and operation of the pollution control facilities and, if applicable, pollution sources.

DARREL JAMES GRAZIANI
44685

Signed Darrel J Graziani 3-1-94

Darrel James Graziani
Name (Please Type)

Ebasco Environmental (1)
Company Name (Please Type)

759 SE Federal Highway
Stuart, FL 34994-2936
Mailing Address (Please Type)

Florida Registration No. 0044685 Date: Exp. 2/28/95 Telephone No. (407) 225-8712

SECTION II: GENERAL PROJECT INFORMATION

A. Describe the nature and extent of the project. Refer to pollution control equipment, and expected improvements in source performance as a result of installation. State whether the project will result in full compliance. Attach additional sheet if necessary.

Installation of a Nominal 74 MW simple cycle combustion turbine (CT) equipped with dry low NO_X combustors for natural gas firing and water injection for fuel oil firing and power augumentation. The CT is expected to operate in full compliance with the applicable regulations.

B. Schedule of project covered in this application (Construction Permit Application On

Start of Construction September 1994 Completion of Construction June 1995

C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

N/A

D. Indicate any previous DER permits, orders and notices associated with the emission point, including permit issuance and expiration dates.

Pursuant to the Power Plant Siting Act, the Deerhaven Generating Station is a "Certified Site" (PA 74-04).

(1) Ebasco Environmental is currently in the process of changing its name to Enserch Environmental.

Requested permitted equipment operating time: hrs/day_____; days/wk_____; wks/yr_____;

if power plant, hrs/yr 3900; if seasonal, describe:

F. If this is a new source or major modification, answer the following questions. (Yes or No)

1. Is this source in a non-attainment area for a particular pollutant? No

   a. If yes, has "offset" been applied? N/A

   b. If yes, has "Lowest Achievable Emission Rate" been applied? N/A

   c. If yes, list non-attainment pollutants. N/A

2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. Yes(1)

3. Does the State "Prevention of Significant Deterioriation" (PSD) requirement apply to this source? If yes, see Sections VI and VII. Yes(2)

4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? Yes(3)

5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? No

H. Do "Reasonably Available Control Technology" (RACT) requirements apply to this source? No

   a. If yes, for what pollutants? N/A

   b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

Attach all supportive information related to any answer of "Yes". Attach any justification for any answer of "No" that might be considered questionable.

(1) See Section 4.0 of the attached PSD application.

(2) PSD is triggered since the project represents a major modification to a major facility.

(3) 40 CFR 60, Subpart GG - New Source Performance Standards for Stationary Combustion Turbines.

SECTION III: AIR POLLUTION SOURCES & CONTROL DEVICES (Other than Incinerators)

A. Raw Materials and Chemicals Used in your Process, if applicable: N/A

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		

B. Process Rate, if applicable: (See Section V, Item 1) N/A

1. Total Process Input Rate (lbs/hr): N/A

2. Product Weight (lbs/hr): N/A

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary) See Attachment No. 1

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/yr	T/yr	

[1] See Section V, Item 2.

[2] Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)

[3] Calculated from operating rate and applicable standard.

[4] Emission, if source operated without control (See Section V, Item 3).

Control Devices: (See Section V, Item 4) N/A

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)

E. Fuels

Data Source: GE Data sheets Attachment A. PSD application

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas	40,700#	45,920#	1,096.6
Fuel Oil Distillate #2	50,380#	50,380#	990.6

*Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.

Avg consumption for Natural Gas represents 100% load at ISO coditions. Max consumption & max heat input represent Natural Gas with power augmentation at 100% load & ISO conditions. Fuel Oil consumption rates represent 100% load at ISO contions.

Fuel Analysis:

Percent Sulfur: NG-10 grs/100 SCF FO-.25/.05 **Percent Ash:** NG-N/A FO-0.01

Density: NG-1 LB/23.8 SCF FO-7.02 **lbs/gal** **Typical Percent Nitrogen:** NG-N/A FO-0.03

Heat Capacity: NG-23,860 FO-19,663 **BTU/lb** (HHV) **BTU/gal**

Other Fuel Contaminants (which may cause air pollution): Fuel Oil - Trace Metals

Arsenic, Beryllium, Lead, Mercury

F. If applicable, indicate the percent of fuel used for space heating. N/A

Annual Average ______ **Maximum** ______

G. Indicate liquid or solid wastes generated and method of disposal.

Waste air filters - solid waste to be disposed offsite. Waste lubrication oils - liquid waste to be sent offsite or used for on site energy recovery

See Section 2.0, Tables 2-1 through 2-7, and Appendix A of the PSD Application

. Emission Stack Geometry and Flow Characteristics (Provide data for each stack):

Stack Height: 52 ft. Stack Diameter: 14.1 ft.

Gas Flow Rate: 1027653 to 1573615 ACFM 316830 to 541621 DSCFM Gas Exit Temperature: 955 to 1100 °F.

Water Vapor Content: 6.59 to 12.78 % Velocity: 104 to 162 FPS

Ranges provided for operating loads of 60 to 100% and ambient temperatures of 20°F to 95°F

SECTION IV: INCINERATOR INFORMATION N/A

Type of Waste	Type 0 (Plastics)	Type I (Rubbish)	Type II (Refuse)	Type III (Garbage)	Type IV (Patholog-ical)	Type V (Liq.& Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Inciner-ated							
Uncon-trolled (lbs/hr)							

escription of Waste ____________________

Total Weight Incinerated (lbs/hr) __________ Design Capacity (lbs/hr) __________

Approximate Number of Hours of Operation per day ______ day/wk ______ wks/yr. ______

Manufacturer ____________________ ______

Date Constructed __________ Model No. __________

	Volume (ft)^3	Heat Release (BTU/hr)	Fuel		Temperature (°F)
			Type	BTU/hr	
Primary Chamber					
Secondary Chamber					

Stack Height: ______ ft. Stack Diamter: ______ Stack Temp. ______

Gas Flow Rate: ______ ACFM ______ DSCFM* Velocity: ______ FPS

*If 50 or more tons per day design capacity, submit the emissions rate in grains per standard cubic foot dry gas corrected to 50% excess air.

Type of pollution control device: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner

[ ] Other (specify) __________

Brief description of operating characteristics of control devices:

Ultimate disposal of any effluent other than that emitted from the stack (scrubber water, ash, etc.):

NOTE: Items 2, 3, 4, 6, 7, 8, and 10 in Section V must be included where applicable.

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)] N/A

To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made. See Attachments 1 and 2

3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
See Attachments 1 and 2
4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.) See Section 4, PSD Application

5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency). N/A

6. An 8 1/2" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained. Figure 2-1, PSD Application

7. An 8 1/2" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Example: Copy of relevant portion of USGS topographic map).
Figure 1-3, PSD Application
8. An 8 1/2" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
Figure 2-2, PSD Application

The appropriate application fee in accordance with Rule 17-4.05. The check should made payable to the Department of Environmental Regulation. N/A covered under PPSA Modification fee

10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit. N/A

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source?

☒ Yes ☐ No 40 CFR 60 Subpart GG

Contaminant	Rate or Concentration @ISO
Sulfur Dioxide	Fuel Spec-0.8%S by weight
Sulfur Dioxide	Exhaust Limit-150 ppmvd @ 15% O_2
Nitrogen Oxides	Fuel Oil 105.8 ppmvd @ 15% O_2
Nitrogen Oxides	Natural Gas - 98.5 ppmvd @ 15% O_2

B. Has EPA declared the ~~best available control technology~~ most stringent emission limits for this class of sources (If yes, attach copy)

☒ Yes ☐ No

Contaminant	Rate or Concentration @ISO
Sulfur Dioxide	Fuel Spec-0.05%S by weight
Nitrogen Oxides	Natural Gas-3.5 ppmvd @ 15% O_2
Nitrogen Oxides	Fuel Oil -11.7ppmvd + FBN Allowance @ 15% O_2

C. What emission levels do you propose as best available control technology?

Contaminant	Rate or Concentration @ISO
Sulfur Dioxide	Fuel Spec-0.05%S by weight
Nitrogen Oxides	Natural Gas-15 ppmvd @ 15% O_2
	Natural Gas/ Power Augmentation-30 ppmvd @15% O
	Fuel Oil-42 ppmvd + FBN Allowance @ 15% O_2

D. Describe the existing control and treatment technology (if any).

1. Control Device/System: DLNO_x/wet Injection
2. Operating Principles: Reduce Thermal NO_x
3. Efficiency: 76-90%
4. Capital Costs: N/A

xplain method of determining EPA ACT Document - EPA-453/R-93-007

5. **Useful Life:** 15 yrs

6. **Operating Costs:** N/A

7. **Energy:** N/A

8. **Maintenance Cost:** N/A

9. **Emissions:**

Contaminant	Rate or Concentration
Nitrogen Oxides	Dry Low NO_x - 15 ppmvd (Natural Gas) @ 15% O_2
Nitrogen Oxides	Water Injection-42 +FBN ppmvd (Fuel Oil) @15% O_2
Nitrogen Oxides	Water Injection-30 ppmvd (NG/Power Augmentation) @15% O_2

10. **Stack Parameters** See Section 2.0, Tables 2-1 through 2-7 of the PSD Application, App

a. **Height:** ft.

b. **Diameter:** ft.

c. **Flow Rate:** ACFM

d. **Temperature:** °F.

e. **Velocity:** FPS

E. **Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary).**

1.

a. **Control Device:** SCR

b. **Operating Principles:** Reaction of NH_3

c. **Efficiency:**[1] 80%

d. **Capital Cost:** 6.3 million

e. **Useful Life:** 15 yrs

f. **Operating Cost:** 1.5 million

g. **Energy**[2] .3590 kwh

h. **Maintenance Cost:** Included in f.

i. **Availability of construction materials and process chemicals:** Good

j. **Applicability to manufacturing processes:** N/A

k. **Ability to construct with control device, install in available space, and operate within proposed levels:** Fair

2. N/A

a. **Control Device:**

b. **Operating Principles:**

c. **Efficiency:**[1]

d. **Capital Cost:**

e. **Useful Life:**

f. **Operating Cost:**

g. **Energy:**[2]

h. **Maintenance Cost:**

i. **Availability of construction materials and process chemicals:**

---

[1] Explain method of determining efficiency. (Act Document EPA 453/R-93-007)

[2] Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

3. N/A

a. Control Device: b. Operating Principles:

c. Efficiency:[1] d. Capital Cost:

e. Useful Life: f. Operating Cost:

g. Energy:[2] h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

4. N/A

a. Control Device: b. Operating Principles:

c. Efficiency:[1] d. Capital Costs:

e. Useful Life: f. Operating Cost:

g. Energy:[2] h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

k. Ability to construct with control device, install in available space, and operate within proposed levels:

F. Describe the control technology selected:

1. Control Device: DL NO_x/Water Injection 2. Efficiency:[1] 76-90%

3. Capital Cost: N/A 4. Useful Life: 15 yrs

5. Operating Cost: N/A 6. Energy:[2] N/A

7. Maintenance Cost: N/A 8. Manufacturer: General Electric

9. Other locations where employed on similar processes: Numerous

a. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

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[1] Explain method of determining efficiency.

[2] Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems: See Section 4.0 of the PSD Application

[1] Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

A. Company Monitored Data N/A

1. ________ no. sites ________ TSP ________ ( ) SO^{2}* ________ Wind spd/di

Period of Monitoring ____ / ____ / ____ to ____ / ____ / ____
month day year month day year

Other data recorded ________________

Attach all data or statistical summaries to this application.

ecify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

a. Was instrumentation EPA referenced or its equivalent? ☐ Yes ☐ No

b. Was instrumentation calibrated in accordance with Department procedures?

☐ Yes ☐ No ☐ Unknown

B. Meteorological Data Used for Air Quality Modeling Obtained from FDEP

1. 5 Year(s) of data from 1 / 1 / 1985 to 12 / 31 / 1989
month day year month day year

2. Surface data obtained from (location) Gainesville, FL

3. Upper air (mixing height) data obtained from (location) Tampa, FL

4. Stability wind rose (STAR) data obtained from (location) N/A

C. Computer Models Used

1. ISCST2 (93109) No Modified? If yes, attach description.

2. VISCREEN (V1.01) No Modified? If yes, attach description.

3. Modified? If yes, attach description.

4. Modified? If yes, attach description.

Attach copies of all final model runs showing input data, receptor locations, and principle output tables. Shipped under separate letter.

D. Applicants Maximum Allowable Emission Data (Table 6-2 PSD Application)

Pollutant	Emission Rate @20°F-100% load	
TSP	1.9	grams/sec
SO^2	33.54	grams/sec

E. Emission Data Used in Modeling

See Tables 6-1 and 6-2 in PSD application

Attach list of emission sources. Emission data required is source name, description of point source (on NEDS point number), UTM coordinates, stack data, allowable emissions, and normal operating time.

F. Attach all other information supportive to the PSD review. See PSD Application

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e., jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources. See PSD Application

H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology. See PSD Application

ATTACHMENT NO. 1

AIRBORNE CONTAMINANTS EMITTED

ATTACHMENT No. 1

Airborne Contaminants Emitted

NATURAL GAS FIRING - 100% Load @ 20 °F

	EMISSION		ALLOWED EMISSION RATE PER RULE	ALLOWABLE EMISSION	POTENTIAL EMISSION	
NAME OF CONTAMINANT	MAXIMUM LBS/HR	ACTUAL T/YR		LBS/HR	LBS/HR	T/YR
CO	35	68	N/A	35	35	68
NOX	58	113	BACT	58	58	113
SO2	29	57	BACT	29	29	57
PM10	7	13.7	BACT	7	7	13.7
TSP	7	13.7	N/A	7	7	13.7
VOC	3	5.9	N/A	3	3	5.9
LEAD	N/A	N/A	N/A	N/A	N/A	N/A
BERYLLIUM	N/A	N/A	N/A	N/A	N/A	N/A
MERCURY	N/A	N/A	N/A	N/A	N/A	N/A
H2SO4	3	5.9	BACT	3.0	3.0	5.9
ARSENIC	N/A	N/A	N/A	N/A	N/A	N/A

NATURAL GAS FIRING - POWER AUGMENTATION, 100% Load @ 59 °F

	EMISSION		ALLOWED EMISSION RATE PER RULE	ALLOWABLE EMISSION	POTENTIAL EMISSION	
NAME OF CONTAMINANT	MAXIMUM LBS/HR	ACTUAL T/YR		LBS/HR	LBS/HR	T/YR
CO	42	8.2	N/A	42	42	8.2
NOX	120	23.4	BACT	120	120	23.4
SO2	30	5.8	BACT	30	30	5.8
PM10	7	1.4	BACT	7	7	1.4
TSP	7	1.4	N/A	7	7	1.4
VOC	4.5	0.88	N/A	4.5	4.5	0.88
LEAD	N/A	N/A	N/A	N/A	N/A	N/A
BERYLLIUM	N/A	N/A	N/A	N/A	N/A	N/A
MERCURY	N/A	N/A	N/A	N/A	N/A	N/A
H2SO4	3.1	0.60	BACT	3.1	3.1	0.60
ARSENIC	N/A	N/A	N/A	N/A	N/A	N/A

FUEL OIL FIRING - 100% Load @ 20 °F

	EMISSION		ALLOWED EMISSION RATE PER RULE	ALLOWABLE EMISSION	POTENTIAL EMISSION	
NAME OF CONTAMINANT	MAXIMUM LBS/HR	ACTUAL T/YR		LBS/HR	LBS/HR	T/YR
CO	71	71	N/A	71	71	71
NOX	237	237	BACT	237	237	237
SO2 (0.05%)	53	53	BACT	53	53	53
SO2 (0.25%)	266	266	As Requested	266	266	266
PM10	15	15	BACT	15	15	15
TSP	15	15	N/A	15	15	15
VOC	7	7	N/A	7	7	7
LEAD	0.0638	0.0638	N/A	0.0638	0.0638	0.0638
BERYLLIUM	0.0004	0.0004	N/A	0.0004	0.0004	0.0004
MERCURY	0.001	0.001	N/A	0.001	0.001	0.001
H2SO4 (0.05%)	5.6	5.6	BACT	5.6	5.6	5.6
H2SO4 (0.25%)	27.8	27.8	BACT	27.8	27.8	27.8

SUPPORT CALCULATIONS FOR ATTACHMENT No. 1

Case 1: Natural Gas Firing @ 100% Load and 20 F

Hourly Emission Rates (GE Data Sheets)

CO = 35 lbs/hr PM10 = 7 lbs/hr VOC = 3 lbs/hr

NOx = 58 lbs/hr TSP = 7 lbs/hr

Hourly Emission Rates (Mass Balance)

SO2 emission estimate is based on 10 grains of sulfur per 100 scf of gas, with a gas density of 23.8 scf/lb, a maximum fuel usage rate of 44990 lbs/hr and 95.1 % conversion to SO2.

$$SO2 = (44990)\cdot(23.8)\cdot\frac{10}{100}\cdot\frac{1}{7000}\cdot\frac{64}{32}\cdot\frac{95.1}{100} = 29.094 \quad \text{lbs/hr}$$

H2SO4 emission estimate is based on 10 grains of sulfur per 100 scf of gas, with a gas density of 23.8 scf/lb, a maximum fuel usage rate of 44990 lbs/hr and 6.5 % conversion to H2SO4.

$$H2SO4 = (44990)\cdot(23.8)\cdot\frac{10}{100}\cdot\frac{6.5}{100}\cdot\frac{1}{7000}\cdot\frac{98}{32} = 3.045 \quad \text{lbs/hr}$$

Annual Emission Rates (TPY), Based on 3,900 hours per year.

$$CO = 35\cdot\frac{3900}{2000} = 68.25 \qquad NOX = 58\cdot\frac{3900}{2000} = 113.1 \qquad PM10 = 7\cdot\frac{3900}{2000} = 13.65$$

$$VOC = 3\cdot\frac{3900}{2000} = 5.85 \qquad TSP = 7\cdot\frac{3900}{2000} = 13.65$$

$$SO2 = 29.094\cdot\frac{3900}{2000} = 56.733 \qquad H2SO4 = 3.045\cdot\frac{3900}{2000} = 5.938$$

Case 2: Natural Gas Firing with Power Augmentation @ 100% Load and ISO Conditions

Hourly Emission Rates (GE Data Sheets)

CO = 42 lbs/hr PM10 = 7 lbs/hr VOC = 4.5 lbs/hr

NOx = 120 lbs/hr TSP = 7 lbs/hr

Hourly Emission Rates (Mass Balance)

SO2 emission estimate is based on 10 grains of sulfur per 100 scf of gas, with a gas density of 23.8 scf/lb, a maximum fuel usage rate of 45920 lbs/hr and 95.1 % conversion to SO2.

$$SO2 = (45920)\cdot(23.8)\cdot\frac{10}{100}\cdot\frac{1}{7000}\cdot\frac{64}{32}\cdot\frac{95.1}{100} = 29.696 \quad \text{lbs/hr}$$

H2SO4 emission estimate is based on 10 grains of sulfur per 100 scf of gas, with a gas density of 23.8 scf/lb, a maximum fuel usage rate of 45920 lbs/hr and 6.5 % conversion to H2SO4.

$$H2SO4 = (45920)\cdot(23.8)\cdot\frac{10}{100}\cdot\frac{6.5}{100}\cdot\frac{1}{7000}\cdot\frac{98}{32} = 3.108 \quad \text{lbs/hr}$$

SUPPORT CALCULATIONS FOR ATTACHMENT No. 1

Case 2: Natural Gas Firing with Power Augmentation @ 100% Load and ISO Conditions

Annual Emission Rates (TPY), Based on 390 hours per year.

$CO = 42 \cdot \frac{390}{2000} = 8.19$ $NOX = 120 \cdot \frac{390}{2000} = 23.4$ $PM10 = 7 \cdot \frac{390}{2000} = 1.365$

$VOC = 4.5 \cdot \frac{390}{2000} = 0.878$ $TSP = 7 \cdot \frac{390}{2000} = 1.365$

$SO2 = 29.696 \cdot \frac{390}{2000} = 5.791$ $H2SO4 = 3.108 \cdot \frac{390}{2000} = 0.606$

Case 3: Fuel Oil @ 100% Load and 20 F

Hourly Emission Rates (GE Data Sheets)

CO = 71 lbs/hr PM10 = 15 lbs/hr VOC = 7 lbs/hr

NOx = 237 lbs/hr TSP = 15 lbs/hr

Hourly Emission Rates (Mass Balance)

SO2 emission estimates are based on 0.25 and 0.05 percent sulfur in the fuel oil, a maximum fuel usage rate of 55940 lbs/hr and 95.1 % conversion to SO2.

$$SO2 = (55940) \cdot \frac{.25}{100} \cdot \frac{64}{32} \cdot \frac{95.1}{100} = 265.995 \quad \text{lbs/hr}$$

$$SO2 = (55940) \cdot \frac{.05}{100} \cdot \frac{64}{32} \cdot \frac{95.1}{100} = 53.199 \quad \text{lbs/hr}$$

H2SO4 emission estimates are based on 0.25 and 0.05 percent sulfur in the fuel oil, a maximum fuel usage rate of 55940 lbs/hr and 6.5 % conversion to H2SO4.

$$H2SO4 = (55940) \cdot \frac{.25}{100} \cdot \frac{6.5}{100} \cdot \frac{98}{32} = 27.839 \quad \text{lbs/hr}$$

$$H2SO4 = (55940) \cdot \frac{.05}{100} \cdot \frac{6.5}{100} \cdot \frac{98}{32} = 5.568 \quad \text{lbs/hr}$$

Trace metal emssion estimates based on a maximum heat input rate of 1100 MMBtu/hr and the emission factors from AP-42, Section 3.1, Table 3.1-7

$$Be = (1100) \cdot \frac{3.3}{10^7} \cdot \frac{2000}{2000} = 3.63 \cdot 10^{-4} \quad \text{lbs/hr}$$

$$Pb = (1100) \cdot \frac{5.8}{10^5} \cdot \frac{2000}{2000} = 0.064 \quad \text{lbs/hr}$$

$$Hg = (1100) \cdot \frac{9.1}{10^7} \cdot \frac{2000}{2000} = 0.001 \quad \text{lbs/hr}$$

Case 3: Fuel Oil @ 100% Load and 20 F

Annual emissions (TPY) based on 2000 hours of operation per year.

CO = $71 \cdot \frac{2000}{2000} = 71$

VOC = $7 \cdot \frac{2000}{2000} = 7$

PM10 = $15 \cdot \frac{2000}{2000} = 15$

NOX = $237 \cdot \frac{2000}{2000} = 237$

SO2 = $53.199 \cdot \frac{2000}{2000} = 53.199$

SO2 = $265.995 \cdot \frac{2000}{2000} = 265.995$

H2SO4 = $5.568 \cdot \frac{2000}{2000} = 5.568$

H2SO4 = $27.839 \cdot \frac{2000}{2000} = 27.839$

Hg = $0.001 \cdot \frac{2000}{2000} = 0.001$

Pb = $0.064 \cdot \frac{2000}{2000} = 0.064$

Be = $3.63 \cdot 10^{-4} \cdot \frac{2000}{2000} = 3.63 \cdot 10^{-4}$

ATTACHMENT NO. 2

SUPPLEMENTAL REQUIREMENTS

SUPPORT CALCULATIONS FOR PSD APPLICATION -ATTACHMENT No. 2

Emission Estimate Basis:

For the CT, the emission estimate was based on 3900 hours of operation a year at ISO conditions. ISO conditions are slightly lower than the annual averages for the Gainesville area. It is expected that use of the ISO conditions will produce slightly higher annual emission estimates. Since the CT can fire natural gas or fuel oil, worst case emissions are based on a combination of operating scenarios. The highest emissions were determined based on the following operating schedule:

Natural Gas Firing - 1510 hrs/yr
Natural Gas Firing with Power Augmentation - 390 hrs/yr
Fuel Oil Firing - 2000 hrs/yr

Emission data were obtain from either the GE data sheets or AP-42. Sulfur dioxide and sulfuric acid mist emissions are being estimated based on 0.25 and 0.05% sulfur by weight content of the fuel oil. Potential emissions are being set equal to actual emissions for purposes of the estimate. Purpose of this emission calculation is to determine PSD applicability. Maximum emissions reflect operation at 100 percent load and an ambient temperature of 20 F, except for NGF/PA which is at 100 % load and ISO conditions. Average emissions reflect operation at 100 percent load and ISO conditions.

Emission Rates:

Carbon Monoxide
Maximum (lbs/hr) NGF - 35, NGF/PA - 42, FOF - 71 (GE data sheets)
Average (lbs/hr) NGF - 32, NGF/PA - 42, FOF - 65 (GE data sheets)

Actual = Potential (TPY)

$$\frac{(32\cdot 1510)+(42\cdot 390)+(65\cdot 2000)}{2000}=97.35$$

Nitrogen Oxides
Maximum (lbs/hr) NGF - 58, NGF/PA - 120, FOF - 237 (GE data sheets)
Average (lbs/hr) NGF - 53, NGF/PA - 120, FOF - 213 (GE data sheets)

Actual = Potential (TPY)

$$\frac{(53\cdot 1510)+(120\cdot 390)+(213\cdot 2000)}{2000}=276.415$$

Paticulate Matter (PM10)
Maximum (lbs/hr) NGF - 7, NGF/PA - 7, FOF - 15 (GE data sheets)
Average (lbs/hr) NGF - 7, NGF/PA - 7, FOF - 15 (GE data sheets)

Actual = Potential (TPY)

$$\frac{(7\cdot 1510)+(7\cdot 390)+(15\cdot 2000)}{2000}=21.65$$

Total Suspended Paticulate (TSP)
Maximum (lbs/hr) NGF - 7, NGF/PA - 7, FOF - 15 (GE data sheets)
Average (lbs/hr) NGF - 7, NGF/PA - 7, FOF - 15 (GE data sheets)

Actual = Potential (TPY)

$$\frac{(7\cdot 1510)+(7\cdot 390)+(15\cdot 2000)}{2000}=21.65$$

Volatile Organic Compounds (VOC)
Maximum (lbs/hr) NGF - 3, NGF/PA - 4.5, FOF - 7 (GE data sheets)
Average (lbs/hr) NGF - 2.8, NGF/PA - 4.5, FOF - 6 (GE data sheets)

Actual = Potential (TPY)

$$\frac{(2.8\cdot 1510)+(4.5\cdot 390)+(6\cdot 2000)}{2000}=8.992$$

Sulfur Dioxide (SO2)
Maximum (lbs/hr) NGF - 29.094, NGF/PA - 29.696, FOF - 266 (Mass Balance)
Average (lbs/hr) NGF - 26.32, NGF/PA - 29.696, FOF - 239.557 (Mass Balance)

Actual = Potential (TPY)

$$\frac{(26.32\cdot 1510)+(29.696\cdot 390)+(239.557\cdot 2000)}{2000}=265.219$$ **SO2 @ 0.25%**

$$\frac{(26.32\cdot 1510)+(29.696\cdot 390)+\frac{239.557}{5}\cdot 2000}{2000}=73.574$$ **SO2 @ 0.05%**

Sulfuric Acid Mist (H2SO4)
Maximum (lbs/hr) NGF - 3.045, NGF/PA - 3.108, FOF - 27.839 (Mass Balance)
Average (lbs/hr) NGF - 2.755, NGF/PA - 3.108, FOF - 25.072 (Mass Balance)

Actual = Potential (TPY)

$$\frac{(2.755\cdot 1510)+(3.108\cdot 390)+(25.072\cdot 2000)}{2000}=27.758$$ **H2SO4 @ 0.25%**

$$\frac{(2.755\cdot 1510)+(3.108\cdot 390)+\frac{25.072}{5}\cdot 2000}{2000}=7.7$$ **H2SO4 @ 0.05%**

Beryllium (Be)
Maximum (lbs/hr) NGF - Neg., NGF/PA - Neg., FOF - 0.00036 (AP-42)
Average (lbs/hr) NGF - Neg., NGF/PA - Neg., FOF - 0.000327 (Ap-42)

Actual = Potential (TPY)

$$\frac{(0\cdot 1510)+(0\cdot 390)+(0.000327\cdot 2000)}{2000}=3.27\cdot 10^{-4}$$

Lead (Pb)
Maximum (lbs/hr) NGF - Neg., NGF/PA - Neg., FOF - 0.0638 (AP-42)
Average (lbs/hr) NGF - Neg., NGF/PA - Neg., FOF - 0.0575 (Ap-42)

Actual = Potential (TPY)

$$\frac{(0\cdot 1510)+(0\cdot 390)+(0.0575\cdot 2000)}{2000}=0.058$$

Mercury (Hg)
Maximum (lbs/hr) NGF - Neg., NGF/PA - Neg., FOF - 0.001 (AP-42)
Average (lbs/hr) NGF - Neg., NGF/PA - Neg., FOF - 0.0000901 (Ap-42)

Actual = Potential (TPY)

$$\frac{(0\cdot 1510)+(0\cdot 390)+(0.000901\cdot 2000)}{2000}=9.01\cdot 10^{-4}$$

Mass Balance Calculations

Sulfur Dioxide: Natural Gas - 10 grains of sulfur per 100 SCF of gas @ 23.8 SCF/lb., with 95.1 % conversion
Maximum Usage - 44990 lbs/hr
Average Usage - 40700 lbs/hr
Power Augmentation - 45920 lbs/hr
Fuel Oil - 0.25 and 0.05% sulfur by weight, with 95.1 % conversion
Maximum Usage - 55940 lbs/hr
Average Usage - 50380 lbs/hr

MW (S) = 32; MW (SO2) = 64: MW (H2SO4) = 98

Natural Gas:

$$\text{Max. (lbs/hr)} = (44990)\cdot(23.8)\cdot\frac{10}{100}\cdot\frac{1}{7000}\cdot\frac{64}{32}\cdot\frac{95.1}{100}=29.094$$

$$\text{Ave. (lbs/hr)} = (40700)\cdot(23.8)\cdot\frac{10}{100}\cdot\frac{1}{7000}\cdot\frac{64}{32}\cdot\frac{95.1}{100}=26.32$$

$$\text{PA (lbs/hr)} = (45920)\cdot(23.8)\cdot\frac{10}{100}\cdot\frac{1}{7000}\cdot\frac{64}{32}\cdot\frac{95.1}{100}=29.696$$

Fuel Oil:

$$\text{Max. (lbs/hr) @ 0.25\%} = (55940)\cdot\frac{0.25}{100}\cdot\frac{64}{32}\cdot\frac{95.1}{100}=265.995 \qquad \text{Max @ 0.05\%}=\frac{265.996}{5}=53.199$$

$$\text{Ave. (lbs/hr) @ 0.25\%} = (50380)\cdot\frac{0.25}{100}\cdot\frac{64}{32}\cdot\frac{95.1}{100}=239.557 \qquad \text{Ave @ 0.05\%}=\frac{239.557}{5}=47.911$$

H2SO4: Natural Gas - 10 grains of sulfur per 100 SCF of gas @ 23.8 SCF/lb.
with 6.5 % of the sulfur converted to H2SO4
Maximum Usage - 44990 lbs/hr
Average Usage - 40700 lbs/hr
Power Augmentation - 45920 lbs/hr
Fuel Oil - 0.25 and 0.05% sulfur by weight with 6.5% of the sulfur converted to H2SO4.
Maximum Usage - 55940 lbs/hr
Average Usage - 50380 lbs/hr
MW (S) = 32; MW (SO2) = 64: MW (H2SO4) = 98

Natural Gas:

Max. (lbs/hr) = $(44990)\cdot(23.8)\cdot\left(\frac{10}{100}\right)\cdot\left(\frac{1}{7000}\right)\cdot\left(\frac{98}{32}\right)\cdot\left(\frac{6.5}{100}\right)=3.045$

Ave. (lbs/hr) = $(40700)\cdot(23.8)\cdot\left(\frac{10}{100}\right)\cdot\left(\frac{1}{7000}\right)\cdot\left(\frac{98}{32}\right)\cdot\left(\frac{6.5}{100}\right)=2.755$

PA (lbs/hr) = $(45920)\cdot(23.8)\cdot\left(\frac{10}{100}\right)\cdot\left(\frac{1}{7000}\right)\cdot\left(\frac{98}{32}\right)\cdot\left(\frac{6.5}{100}\right)=3.108$

Fuel Oil:

Max. (lbs/hr) @ 0.25% = $(55940)\cdot\left(\frac{0.25}{100}\right)\cdot\left(\frac{98}{32}\right)\cdot\left(\frac{6.5}{100}\right)=27.839$ Max @ 0.05% = $\frac{27.839}{5}=5.568$

Ave. (lbs/hr) @ 0.25% = $(50380)\cdot\left(\frac{0.25}{100}\right)\cdot\left(\frac{98}{32}\right)\cdot\left(\frac{6.5}{100}\right)=25.072$ Ave @ 0.05% = $\frac{25.072}{5}=5.014$

AP-42 Calculations

Emission Factors:

Beryllium = 3.3E-7 lbs/mmBtu
Lead = 5.8E-5 lbs/mmBtu
Mercury = 9.1 E-7 lbs/mmBtu

Heat Input Rates:

FOF (Max.) = 1100 mmBtu/hr
FOF (Ave.) = 990.6 mmBtu/hr

Beryllium

Max. (lbs/hr) = $(1100)\cdot\left(\frac{3.3}{10^7}\right)=3.63\cdot10^{-4}$

Ave. (lbs/hr) = $(990.6)\cdot\left(\frac{3.3}{10^7}\right)=3.269\cdot10^{-4}$

Lead

Max. (lbs/hr) = $(1100)\cdot\left(\frac{5.8}{10^5}\right)=0.0638$

Ave. (lbs/hr) = $(990.6)\cdot\left(\frac{5.8}{10^5}\right)=0.0575$

Mercury

Max. (lbs/hr) = $(1100)\cdot\left(\frac{9.1}{10^7}\right)=0.001$

Ave. (lbs/hr) = $(990.6)\cdot\left(\frac{9.1}{10^7}\right)=9.014\cdot10^{-4}$

SUPPORT CALCULATIONS FOR THE AIR TOXICS ANALYSIS

References: AP-42, Supplement F, Section 3.1, Table 3-7 and
Air Emissions Species Manual,
Volume I Volatile Organic Compound Species Profiles,
Second Edition, Profile 0007

Basis: AP-42 provides emission factors for various trace metals emitted during the firing of distillate fuel oil. In addition, AP-42 identifies formaldehyde emissions from natural gas fired units equipped with Select Catalytic Reduction. Since the AP-42 trace metal emission factors are based on heat input rates of the combustion turbine the air toxics analysis focused on the maximum heat input rate. For fuel oil firing this maximum heat input rate cooresponds to the 100 % load at 20 F operating case. For the formaldehyde emissions, review of the Species Manual indicates a 30/70 split of the VOC emissions between formaldehyde and methane. For natural gas firing the maximum VOC emissions correspond to the 100 % load at ISO conditions. All VOC emissions were assumed to be formaldehyde for a conservative approach.

Trace Metal Emissions:

Maximum Heat Input Rate: 1100 mmBtu/hr @ 100% load and 20 F (GE Data Sheets)

Antimony (grams/sec)

$$(1100)\cdot\left(\frac{2.2}{10^5}\right)\cdot\left(\frac{454}{3600}\right)=3.05\cdot10^{-3}$$

Lead (grams/sec)

$$(1100)\cdot\left(\frac{5.8}{10^5}\right)\cdot\left(\frac{454}{3600}\right)=8.05\cdot10^{-3}$$

Arsenic (grams/sec)

$$(1100)\cdot\left(\frac{4.9}{10^6}\right)\cdot\left(\frac{454}{3600}\right)=6.8\cdot10^{-4}$$

Managese (grams/sec)

$$(1100)\cdot\left(\frac{3.4}{10^4}\right)\cdot\left(\frac{454}{3600}\right)=4.72\cdot10^{-2}$$

Beryllium (grams/sec)

$$(1100)\cdot\left(\frac{3.3}{10^7}\right)\cdot\left(\frac{454}{3600}\right)=4.58\cdot10^{-5}$$

Mercury (grams/sec)

$$(1100)\cdot\left(\frac{9.1}{10^7}\right)\cdot\left(\frac{454}{3600}\right)=1.26\cdot10^{-4}$$

Cadmium (grams/sec)

$$(1100)\cdot\left(\frac{4.2}{10^6}\right)\cdot\left(\frac{454}{3600}\right)=5.83\cdot10^{-4}$$

Selenium (grams/sec)

$$(1100)\cdot\left(\frac{5.3}{10^6}\right)\cdot\left(\frac{454}{3600}\right)=7.35\cdot10^{-4}$$

Chromium (grams/sec)

$$(1100)\cdot\left(\frac{4.7}{10^5}\right)\cdot\left(\frac{454}{3600}\right)=6.52\cdot10^{-3}$$

Nickel (grams/sec)

$$(1100)\cdot\left(\frac{1.2}{10^3}\right)\cdot\left(\frac{454}{3600}\right)=1.66\cdot10^{-1}$$

Cobalt (grams/sec)

$$(1100)\cdot\left(\frac{9.1}{10^6}\right)\cdot\left(\frac{454}{3600}\right)=1.26\cdot10^{-3}$$

Formaldehyde emissions are being estimated based on the maximum VOC emission rate during natural gas firing. This cooresponds to the power augmentation mode at iso conditions. From the GE data sheets the maximum VOC emission rate is 4.5 pounds per hour. For this analysis all VOC emissions are assumed to be formaldehyde.

Formaldehyde (grams/sec)

$$(4.5)\cdot\left(\frac{454}{3600}\right) = 5.68\cdot 10^{-1}$$

Maximum 8-hour, 24-hour and annual impacts are based on the results of the dispersion modelling runs for particulate matter (ISC2 - Model). These maximum impacts which correpond to a 1 gram per second emission rate are as follows:

8-hour (ug/m3) = 0.13702
24-hour (ug/m3) = 0.06108
Annual (ug/m3) = 0.00313

For the CT emissions the maximum impacts are determined by mutipling the maximum emission rate by the maximum impact for the short term averaging periods. The long term impacts are scaled by factors of 2000/8760 and 3900/8760 for fuel oil firing and natural gas firing, respectively.

Hazardous Air Pollutant Impacts:

Formaldehyde:

8-hour (ug/m3)

$$\left[\frac{(5.68)}{10^1}\right]\cdot(0.13702) = 7.78\cdot 10^{-2}$$

24-hour (ug/m3)

$$\left(\frac{05.68}{10^1}\right)\cdot(0.06108) = 3.47\cdot 10^{-2}$$

Annual (ug/m3)

$$\left(\frac{05.68}{10^1}\right)\cdot(0.00313)\cdot\left(\frac{3900}{8760}\right) = 7.92\cdot 10^{-4}$$

Antimony:

8-hour (ug/m3)

$$\left(\frac{03.05}{10^3}\right)\cdot(0.13702) = 4.18\cdot 10^{-4}$$

24-hour (ug/m3)

$$\left(\frac{03.05}{10^3}\right)\cdot(0.06108) = 1.86\cdot 10^{-4}$$

Annual (ug/m3)

$$\left(\frac{03.05}{10^3}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 2.18\cdot 10^{-6}$$

Arsenic:

8-hour (ug/m3)

$$\left(\frac{6.8}{10^4}\right)\cdot(0.13702) = 9.32\cdot 10^{-5}$$

24-hour (ug/m3)

$$\left(\frac{6.8}{10^4}\right)\cdot(0.06108) = 4.15\cdot 10^{-5}$$

Annual (ug/m3)

$$\left(\frac{6.8}{10^4}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 4.86\cdot 10^{-7}$$

Beryllium:

8-hour (ug/m3)

$$\left(\frac{4.58}{10^5}\right)\cdot(0.13702) = 6.28\cdot 10^{-6}$$

24-hour (ug/m3)

$$\left(\frac{4.58}{10^5}\right)\cdot(0.06108) = 2.8\cdot 10^{-6}$$

Annual (ug/m3)

$$\left(\frac{4.58}{10^5}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 3.27\cdot 10^{-8}$$

Cadmium:

8-hour (ug/m3)

$$\left(\frac{5.83}{10^4}\right)\cdot(0.13702) = 7.988\cdot 10^{-5}$$

24-hour (ug/m3)

$$\left(\frac{5.83}{10^4}\right)\cdot(0.06108) = 3.561\cdot 10^{-5}$$

Annual (ug/m3)

$$\left(\frac{5.83}{10^4}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 4.1662\cdot 10^{-7}$$

Chromium:

8-hour (ug/m3)

$$\left(\frac{6.53}{10^3}\right)\cdot(0.13702) = 8.95\cdot 10^{-4}$$

24-hour (ug/m3)

$$\left(\frac{6.53}{10^3}\right)\cdot(0.06108) = 3.99\cdot 10^{-4}$$

Annual (ug/m3)

$$\left(\frac{6.53}{10^3}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 4.67\cdot 10^{-6}$$

Cobalt:

8-hour (ug/m3)

$$\left(\frac{1.26}{10^3}\right)\cdot(0.13702) = 1.73\cdot 10^{-4}$$

24-hour (ug/m3)

$$\left(\frac{1.26}{10^3}\right)\cdot(0.06108) = 7.7\cdot 10^{-5}$$

Annual (ug/m3)

$$\left(\frac{1.26}{10^3}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 9\cdot 10^{-7}$$

Lead:

8-hour (ug/m3)

$$\left(\frac{8.05}{10^3}\right)\cdot(0.13702) = 1.1\cdot 10^{-3}$$

24-hour (ug/m3)

$$\left(\frac{8.05}{10^3}\right)\cdot(0.06108) = 4.92\cdot 10^{-4}$$

Annual (ug/m3)

$$\left(\frac{8.05}{10^3}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right) = 5.75\cdot 10^{-6}$$

Manganese:

8-hour (ug/m3)

$$\left(\frac{4.72}{10^2}\right)\cdot(0.13702)=6.47\cdot10^{-3}$$

24-hour (ug/m3)

$$\left(\frac{4.72}{10^2}\right)\cdot(0.06108)=2.88\cdot10^{-3}$$

Annual (ug/m3)

$$\left(\frac{4.72}{10^2}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right)=3.37\cdot10^{-5}$$

Mercury:

8-hour (ug/m3)

$$\left(\frac{1.26}{10^4}\right)\cdot(0.13702)=1.73\cdot10^{-5}$$

24-hour (ug/m3)

$$\left(\frac{1.26}{10^4}\right)\cdot(0.06108)=7.7\cdot10^{-6}$$

Annual (ug/m3)

$$\left(\frac{1.26}{10^4}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right)=9\cdot10^{-8}$$

Nickel:

8-hour (ug/m3)

$$\left(\frac{1.66}{10^1}\right)\cdot(0.13702)=2.27\cdot10^{-2}$$

24-hour (ug/m3)

$$\left(\frac{1.66}{10^1}\right)\cdot(0.06108)=1.01\cdot10^{-2}$$

Annual (ug/m3)

$$\left(\frac{1.66}{10^1}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right)=1.19\cdot10^{-4}$$

Selenium:

8-hour (ug/m3)

$$\left(\frac{7.35}{10^4}\right)\cdot(0.13702)=1.01\cdot10^{-4}$$

24-hour (ug/m3)

$$\left(\frac{7.35}{10^4}\right)\cdot(0.06108)=4.49\cdot10^{-5}$$

Annual (ug/m3)

$$\left(\frac{7.35}{10^4}\right)\cdot(0.00313)\cdot\left(\frac{2000}{8760}\right)=5.25\cdot10^{-7}$$

TABLE 3.1-7. TRACE ELEMENT EMISSION FACTORS FOR DISTILLATE OIL-FIRED GAS TURBINES[a]
(Source Classification Code: 20100101)

EMISSION FACTOR RATING: E[b]

Trace Element	pg/J	lb/MMBtu
Aluminum	64	1.5 E-04
Antimony	9.4	2.2 E-05
Arsenic	2.1	4.9 E-06
Barium	8.4	2.0 E-05
Beryllium	.14	3.3 E-07
Boron	28	6.5 E-05
Bromine	1.8	4.2 E-06
Cadmium	1.8	4.2 E-06
Calcium	330	7.7 E-04
Chromium	20	4.7 E-05
Cobalt	3.9	9.1 E-06
Copper	578	1.3 E-03
Iron	256	6.0 E-04
Lead	25	5.8 E-05
Magnesium	100	2.3 E-04
Manganese	145	3.4 E-04
Mercury	.39	9.1 E-07
Molybdenum	3.6	8.4 E-06
Nickel	526	1.2 E-03
Phosphorus	127	3.0 E-04
Potassium	185	4.3 E-04
Selenium	2.3	5.3 E-06
Silicon	575	1.3 E-03
Sodium	590	1.4 E-03
Tin	35	8.1 E-05
Vanadium	1.9	4.4 E-06
Zinc	294	6.8 E-04

[a] Reference 1.

[b] Emission factor rating of "E" indicates that the data are from a limited data set and may not be representative of a specific source or population of sources.

```
VOC Profile Speciation Report
---------------------------------------------------------------------------------------
Profile Name   : Natural Gas Turbine
Profile Number : 0007
Data Quality   : C
---------------------------------------------------------------------------------------
Control Device : Uncontrolled
Reference(s)   : 58, 59
Data Source    : Composite profile developed using data based on GC/MS
                 analysis of fuel combustion exhaust.

SCC Assignments: 20200201

---------------------------------------------------------------------------------------
Saroad       CAS Number       Name                             Spec_MW   Spec_WT   Peak
---------------------------------------------------------------------------------------
43201           74-82-8       METHANE                            16.04     70.00
43502           50-00-0       FORMALDEHYDE                       30.03     30.00
---------------------------------------------------------------------------------------
TOTAL                                                                     100.00
=======================================================================================
```

SUPPORT CALCULATIONS FOR THE BACT DETERMINATION

The BACT analysis focused on the addition of a Selective Catalytic Reduction (SCR) system equipped with a high temperature zeolite catalyst and an air injection system to reduce emission of nitrogen oxides. The base equipment cost estimate was provided by the Norton ChemicalProcess Products Corporation and is the basis of the cost estimate. The most stringent emission limits were set at 3.5 and 11.7 ppmvd @ 15 % O2 for natural gas firing and fuel oil firing respectively. Option #1 estimates emissions based on the application of a SCR system which can reduce emissions levels from 15/30/54 ppm @ 15 % O2 to those of the most stringent emission limits identified by the BACT analysis. Option #2 estimates emissions based on the use of dry low NOx combustors for NGF and water injection for NGF/PA and FOF.

Operating Schedule
NGF - 1510 hrs/yr
NGFPA - 390 hrs/yr
FOF - 2000 hrs/yr

Option #1 Estimated Emission Levels

NGF (lbs/hr)	NGFPA (lbs/hr)	FOF (lbs/hr)
$(53)\cdot\frac{3.5}{15} = 12.37$	$(120)\cdot\frac{3.5}{30} = 14$	$(213)\cdot\frac{11.7}{54} = 46.15$

For emission estimating purposes the emission rates from the GE data sheets were merely scaled to reflect the Option # 1 emission limits.

Option # 2 Emission Levels

NGF (lbs/hr)	NGFPA (lbs/hr)	FOF (lbs/hr)
53	120	213

Emission estimates based on the GE data sheets.

Annual Emission Levels

Option # 1

$$\text{TPY} = \frac{(12.367)\cdot(1510) + (14)\cdot(390) + (46.15)\cdot 2000}{2000} = 58.22$$

Option # 2

$$\text{TPY} = \frac{((53)\cdot(1510) + (120)\cdot 390) + (213)\cdot 2000}{2000} = 276.42$$

Net Reduction (TPY)

$$276.42 - 58.22 = 218.2$$

Incremental Cost Effectiveness

Total Annual Costs (1993 $) = 1,455,957.53
Total Net Reductions (TPY) = 218.2

$$\text{Incremental Cost Effectiveness (\$/Ton)} = \frac{1455957.53}{218.2} = 6672.58$$

SUPPORT CALCULATION FOR SULFUR CONVERSION RATES

The GE data sheets have provided emission estimates of sulfur dioxide (SO_2) for the fuel oil firing mode These emission estimates were based on a certain percentage of sulfur in the fuel oil being converted to SO_2. In order to ensure consistency with the GE data these conversion factors were calculated and applied to natural gas firing as well as fuel oil.

Knowns: At 100% load, 95F and a relative humidity of 50 %, the maximum fuel oil flow is 44940 lbs/hr.
At these conditions H_2SO_4 = 41 lbs/hr, SO_2= 393 lbs/hr and SO_3=25 lbs/hr.
These emission rates correspond to a fuel oil sulfur content of 0.46% by weight
MW(S)=32, MW(SO_2)=64, MW(H_2SO_4)=98, MW(SO_3)=80

Reactions:

$S + O_2 = SO_2$	1:1 mole ratio
$S + (3/2)O_2 = SO_3$	1:1 mole ratio
$SO_3 + H_2O = H_2SO_4$	1:1 mole ratio

Calculations:

Maximum available sulfur for conversion:

$$(44940)\cdot\frac{0.46}{100} = 206.724 \quad \text{lbs/hr}$$

Sulfur converted for SO_2 formation:

$$(393)\cdot\frac{32}{64} = 196.5 \quad \text{lbs/hr} \qquad \frac{196.5}{206.724} = 0.951 \quad \text{Fraction}$$

Sulfur converted for SO_3 formation:

$$(25)\cdot\frac{32}{80} = 10 \quad \text{lbs/hr} \qquad \frac{10}{206.724} = 0.048 \quad \text{Fraction}$$

Sulfur converted for H_2SO_4 formation:

$$(41)\cdot\frac{32}{98} = 13.388 \quad \text{lbs/hr} \qquad \frac{13.388}{206.724} = 0.065 \quad \text{Fraction}$$

Total fraction of sulfur converted:

$$0.951 + 0.048 + 0.065 = 1.064$$

This relates to 95.1 % of the available sulfur being converted to SO_2. The remaining fractions are conservative estimates for SO_3 and H_2SO_4 formation.

SUPPORT CALCULATIONS FOR NSPS EMISSION LIMITATIONS

This calculation examines the allowable emission rates pursuant to 40 CFR 60, Subpart GG - New Source Performance Standards for Stationary Gas Turbines.

Natural Gas Lower Heating Value (Btu/lb) = 21,157.82
Fuel Oil Lower Heating Value (Btu/lb) = 18,550
Fuel Oil Fuel Bound Nitrogen Content = 0.03 % by weight
Fuel Oil Sulfur Content = 0.25 % by weight

Natural Gas Firing at ISO conditions and 100 % load:
Natural Gas Flow Rate (lbs/hr) = 40,700
Gross Output (kW) = 82,810

Natural Gas Firing with Power Aug. at ISO conditions and 100 % load:
Natural Gas Flow Rate (lbs/hr) = 45,920
Gross Output (kW) = 89,580

Fuel Oil Firing at ISO conditions and 100 % load:
Fuel Oil Flow Rate (lbs/hr) = 50,380
Gross Output (kW) = 85,580

NSPS NOx Limitation
STD = 0.0075 X (14.4/Y) + F
STD - Standard in percent volume at 15 % O2
Y - Heat Rate (kilojoules per watt hour)
F - Fuel Bound Nitrogen Allowance
F = 0.040 X maximum fuel bound nitrogen content

Calculate Y

$$\underline{\text{NGF}}\qquad Y = (40700)\cdot(21157.8215)\cdot\frac{1054.35}{1000}\cdot\frac{1}{1000}\cdot\frac{1}{82810} = 10.964$$

$$\underline{\text{NGF/PA}}\qquad Y = (45920)\cdot(21157.8215)\cdot\frac{1054.35}{1000}\cdot\frac{1}{1000}\cdot\frac{1}{89580} = 11.435$$

$$\underline{\text{FOF}}\qquad Y = (50380)\cdot(18550)\cdot\frac{1054.35}{1000}\cdot\frac{1}{1000}\cdot\frac{1}{85580} = 11.514$$

Emission Limitations (% volume at ISO conditions and corrected to 15 % O2)

$$\underline{\text{NGF}}\qquad (0.0075)\cdot\frac{14.4}{10.964} + 0 = 0.00985$$

$$\underline{\text{NGF/PA}}\qquad (0.0075)\cdot\frac{14.4}{11.435} + 0 = 0.00944$$

$$\underline{\text{FOF}}\qquad (0.0075)\cdot\frac{14.4}{11.514} + 0.040\cdot(.03) = 0.01058$$

Conversion Factors:

1000 joules/kilojoule
1054.35 joules/Btu
1000 watts/kilowatt

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION FOR GAINESVILLE REGIONAL UTILITIES (GRU) DEERHAVEN GENERATING STATION COMBUSTION TURBINE ADDITION

Gainesville Regional Utilities
301 SE 4th Ave.
Gainesville, FL 32601

March 1994

Prepared by:
ENSERCH Environmental Corporation
formerly the Environmental Division of Ebasco Services Incorporated
145 Technology Park
Norcross, GA 30092

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EXECUTIVE SUMMARY

Gainesville Regional Utilities (GRU) is planning to install a 74 MW (nominal), dual fuel, simple cycle combustion turbine (CT) at its existing Deerhaven Site approximately seven miles north of Gainesville, in Alachua County. The existing Deerhaven Station consists of two steam generating units (a nominal 81 MW gas/oil fired unit (Unit 1) and a nominal 235 MW coal-fired unit (Unit 2)), and two nominal 22 MW gas/oil fired CTs. The addition of the new CT is being treated as a modification to the existing site certification (PA74-04) under Florida Power Plant Siting Act Chapter 403 Part II, F.S. based upon its location within a "certified site". This Prevention of Significant Deterioration (PSD) Application is being submitted in conjunction with the modification request.

The selected CT, designated as DHCT3, is a General Electric (GE) Model MS7001EA dry low NO_x combustor unit which will fire natural gas as the primary fuel and low sulfur distillate fuel oil as a backup fuel. The unit will function as an intermediate peaking unit and will operate up to a maximum of 3,900 hours per year.

Under federal and Florida Department of Environmental Protection (FDEP) PSD regulations, all major new sources or modifications of major existing sources located in attainment areas must undergo the following analyses for each pollutant emitted in significant quantities: (1) a control technology analysis; (2) an air quality impacts analysis; and (3) an additional impacts analysis. The source must also be reviewed with respect to Good Engineering Practice (GEP) stack height limitations, compliance with New Source Performance Standards (NSPS), and compliance with state emission limits. The control technology analysis consists of a demonstration that the Best Available Control Technology (BACT) will be used to limit pollutant emissions. The air quality impacts analysis involves an assessment of the existing air quality and an analysis of whether the impacts of the proposed source will comply with the allowable Ambient Air Quality Standards (AAQS) and not cause exceedances of the allowable PSD increments either in the site vicinity or in any nearby Class I PSD areas.

The proposed project is located in an attainment area and is thus subject to the PSD permitting requirements. It is considered a major modification to a major existing source and is subject to PSD review for the following pollutants: NO_x, SO_2, PM_{10}, and H_2SO_4. It is not subject to PSD review for other regulated air pollutants because the emissions of these pollutants will be less than the FDEP thresholds which trigger PSD review.

The BACT analysis for the project considered all of the pollutants subject to PSD, as indicated above. The analysis examined the environmental, energy, and economic considerations for those pollution control strategies determined to be technically feasible. In accordance with FDEP guidance, a "top-down" approach was utilized whereby the maximum degree of control required for a similar source in the U.S. was determined by reviewing EPA BACT Clearinghouse and California BACT Clearinghouse information. The most stringent emission limitations would be considered as BACT for this project unless the emission limitation is either technically infeasible or of unreasonable cost when considering environmental, energy, and economic factors.

In the case of NO_x control, two options were examined: (1) Selective Catalytic Reduction (SCR) technology using special high temperature zeolite catalysts (this was considered to be potentially technically feasible), and (2) dry low NO_x combustion technology for natural gas firing conditions and water injection during distillate fuel oil firing. The analysis indicated that the SCR option is unreasonably expensive. BACT for NO_x was determined to be dry low NO_x combustion technology for natural gas firing and water injection during distillate fuel oil firing.

For SO_2 and H_2SO_4 control, BACT was determined to be fuel quality specification and a limitation on the hours of operation on distillate fuel oil. The sulfur content in natural gas is minimal and meets BACT. For distillate fuel oil, BACT was determined to be the low sulfur (0.05 percent by weight) distillate fuel required by the Clean Air Act Amendments of 1990 as a transportation fuel. GRU will restrict future purchases of distillate fuel oil at this facility to this sulfur content but requests FDEP permission to fire the existing on-site supply of distillate, which has a sulfur content of 0.25 percent, until that supply is drawn down.

For PM_{10} control, the analysis determined that BACT is a combination of combustion air filtration, good combustion practices, use of clean burning natural gas, and a limitation on hours of fuel oil firing.

With respect to the other review requirements, the proposed stack height of 52.0 feet was found to be within the GEP stack height requirements. The applicable NSPS was determined to be 40 CFR 60 Subpart GG, and the proposed CT will comply with its requirements. Finally, the only additional state emission limits which apply to the proposed CT are a 20 percent opacity visible emissions limit and a prohibition on objectionable odors. The project will comply with these state restrictions.

The existing air quality in the site area was evaluated through the use of data from existing monitoring sites. Monitoring is not required by FDEP in cases where a proposed source will have ambient impacts below certain de minimis concentrations. GRU demonstrated that the impacts from the proposed CT will be below these levels and FDEP granted GRU's monitoring exemption request. Background air quality monitoring data from Gainesville, Palatka, and Jacksonville indicated that existing ambient concentrations are low and well within the allowable AAQS.

The modelling protocol for and receptor point grids used in the air quality impacts analysis were approved by FDEP. The ISCST2 dispersion model was the primary model used to analyze the impacts of the proposed CT. The analysis used five years of meteorological data from Gainesville (surface) and Tampa (upper air) which was supplied by FDEP. The emissions data used in the modelling represented "worst-case" conditions based on a range of fuels, operating scenarios, and ambient conditions. Downwash from the stack was evaluated in accordance with FDEP modelling guidelines.

Air quality screening modelling identified various combinations of CT load, ambient temperature, and fuel which produced "worst-case" ground-level concentrations for the different pollutants and averaging times. These worst-case combinations were modelled in more detail to determine if there would be any significant (as defined in Ch. 17-212.200(63) F.A.C.) off-site impacts. The modelling confirmed that there will be no significant off-site impacts due to the proposed CT and that additional modelling of existing sources in combination with the proposed CT was not necessary. Maximum off-site impacts due to the proposed CT were compared with Florida and National AAQS and the applicable Class II PSD increments. These were found to be well within the allowable limits.

The potential impacts of the proposed CT on the nearest Class I PSD areas were evaluated in accordance with procedures approved by FDEP and compared with the National Park Service significance criteria. The modelling results indicated that the project will not have a significant impact on the Class I areas.

An analysis of hazardous air pollutants was conducted based on FDEP guidelines. Using conservative, worst-case assumptions for emission rates and meteorological conditions the potential ambient impacts of twelve (12) hazardous air pollutants, primarily metals contained in distillate fuel oil, were evaluated. The maximum predicted impacts were below FDEP's draft No Threat Levels, and therefore no further analysis was necessary.

An additional impacts analysis conducted in accordance with the PSD requirements determined that project-related growth will not significantly affect air quality or visibility, soils and vegetation in the Class I areas.

The proposed project will apply BACT to control its emissions, will meet other state emission requirements, will comply with AAQS and PSD increment requirements, will not cause exceedances of FDEP's draft No Threat Levels, and will not cause any other significant air quality problems. Therefore, reasonable assurances have been provided to support FDEP's issuance of a PSD permit for the project.

Section I.

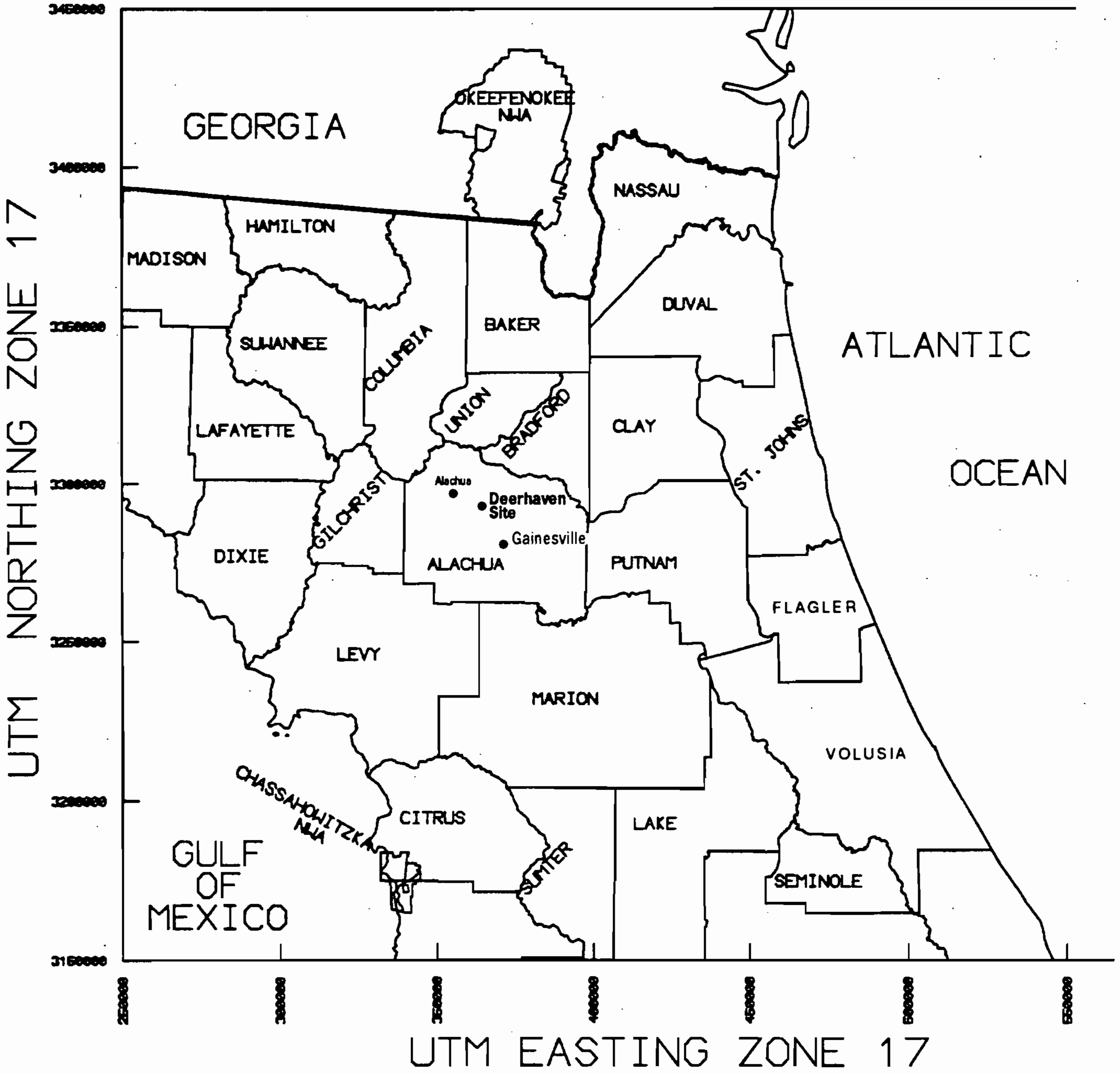
1.0 INTRODUCTION

Gainesville Regional Utilities (GRU) is planning to install a 74 MW (nominal), dual fuel, simple cycle combustion turbine (CT) at its Deerhaven Generating Station site approximately seven miles north of Gainesville, in Alachua County. The project is designed to allow its integration into existing facilities. Ebasco Services Incorporated has been contracted to engineer and construct the CT and ENSERCH Environmental (formerly the Environmental Division of Ebasco Services Incorporated) has been contracted to assist GRU with the environmental permitting. Figure 1-1 presents a general location map of the area and Figure 1-2 is a site location map. Figure 1-3 presents the existing Deerhaven site layout with the location of the proposed CT identified.

The existing Deerhaven Generating Station consists of two steam generating units (a nominal 81 MW gas/oil-fired unit (Unit 1) and a nominal 235 MW coal-fired unit (Unit 2)), and two nominal 22 MW gas/oil fired combustion turbines, designated DHCT1 and DHCT2. The coal-fired unit was licensed through the Florida Power Plant Siting Act (PPSA) process (GRU, 1977). Thus, the Deerhaven Generating Station is a "certified site" under the PPSA's jurisdiction. The addition of the new gas/oil fired combustion turbine is being treated as a modification of the 1978 site certification. This Prevention of Significant Deterioration (PSD) application is being submitted in conjunction with the modification request rather than as a separate federal application because the Florida Department of Environmental Protection (FDEP) has been authorized to issue PSD permits for projects covered by the Power Plant Siting Act.

The U.S. Environmental Protection Agency (EPA) has promulgated Prevention of Significant Deterioration (PSD) regulations (40 CFR 52.21), which require a permit review and approval for new or modified existing sources that increase air pollutant emissions above specified threshold levels. These emission threshold levels will be exceeded by the project. As a result, the project is subject to PSD review. The federal PSD regulations are implemented by FDEP through EPA approval of Florida's PSD program. FDEP's PSD regulations are codified in the Florida Administrative Code (F.A.C.) Ch.17-212.400. The FDEP Application to Operate/Construct Air Pollution Sources for the project is attached to the front of this document.

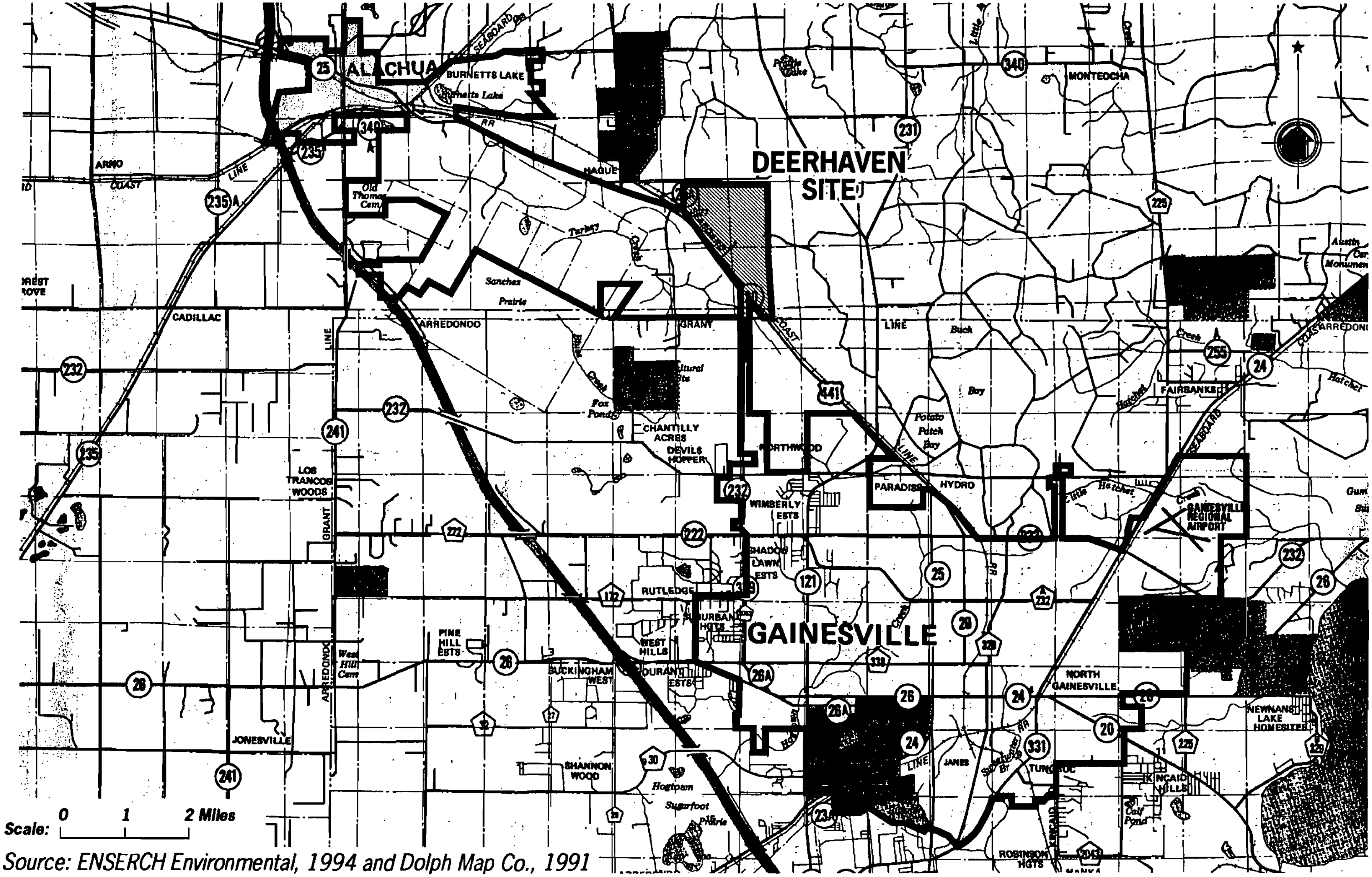
The technical information and analysis required by the federal and state PSD regulations is contained in this PSD permit application. Although this document is associated with a Request for Modification of Site Certification (PA74-04) to incorporate the proposed facility,



Source: ENSERCH Environmental, 1994

REGIONAL LOCATION MAP
Alachua County, Florida

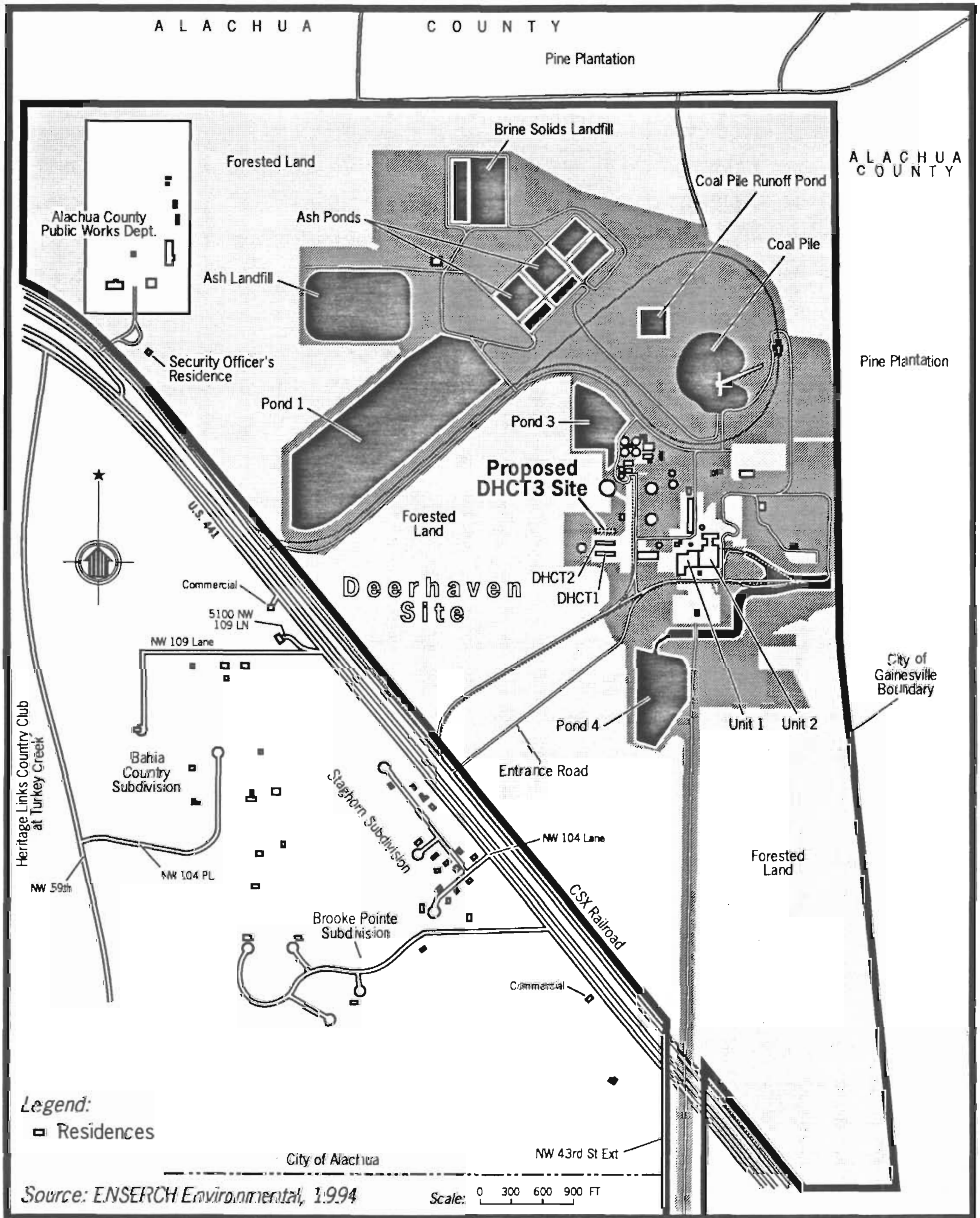
FIGURE
1-1



Source: ENSERCH Environmental, 1994 and Dolph Map Co., 1991

DEERHAVEN SITE LOCATION
Alachua County, Florida

FIGURE
1-2



Source: ENSERCH Environmental, 1994

GRU

DEERHAVEN SITE PLAN

FIGURE 1-3

it has been prepared as a stand-alone PSD permit application. The permit application is divided into eight major sections. Presented in Section 2.0 is a description of the project including the new CT's air pollutant emissions and stack parameters. Air quality review requirements and applicability are presented in Section 3.0. The best available control technology (BACT) analysis is presented in Section 4.0. An ambient air quality monitoring data analysis is presented in Section 5.0, and the air quality modelling methodology, the results of the air quality impact assessment, and additional air quality analyses performed for the proposed project are presented in Sections 6.0, 7.0, and 8.0, respectively. A brief conclusion is presented in Section 9.0. Section 10.0 contains a list of references and materials cited. Copies of the emissions source material and calculations are included as Appendices. Completed application forms are attached at the front of this document.

Section II

2.0 PROJECT DESCRIPTION

2.1 GENERAL DESCRIPTION

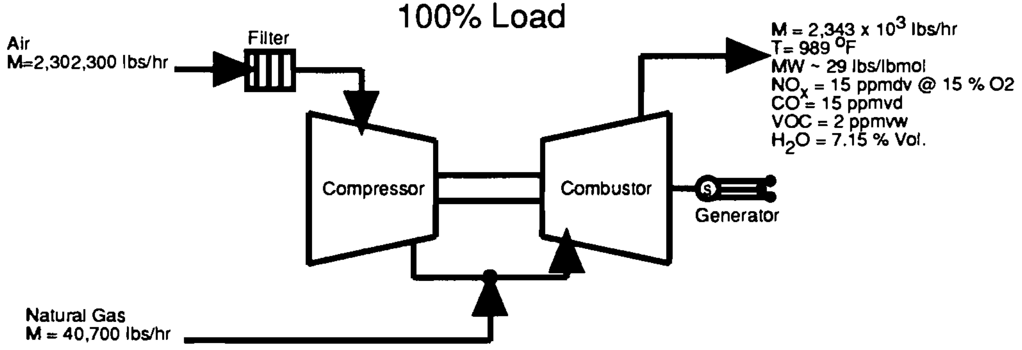
The proposed project will consist of the construction of a new simple cycle combustion turbine (CT) at the existing Deerhaven Generating Station. It will be designated as DHCT3. The new CT will provide a nominal 74 MW of additional generating capacity to the site. The CT will fire natural gas as the primary fuel, with low sulfur fuel oil as backup and will function as an intermediate peaking unit, operating no more than 3,900 hours per year. The CT selected is a General Electric (GE) Model MS7001EA dry low NO_x unit. It will be capable of operating in any of three modes: natural gas firing (NGF), natural gas firing with power augmentation (NGFPA) or distillate fuel oil firing (FOF). A simplified flow diagram for International Standards Organization (ISO) conditions (59°F, 60% relative humidity, sea level pressure) is provided in Figure 2-1.

NGFPA operation (which will be limited to a maximum of 390 hours per year) is accomplished by introducing water into the CT combustors slightly downstream of the flame. During this time, the combustion mode is more like that of a conventional combustor with the water serving to help reduce emissions. This is not as effective control as with the dry low NO_x combustors in the pre-mix mode (NGF). Since the CT is a mass flow device, the addition of the water increases the output by about eight percent (8%) over the normal maximum power output. This type of operation will be limited to those times when the system demand is higher than the capacity available from existing on-line generation.

During NGF operations, oxides of nitrogen (NO_x) emissions will be controlled through the use of staged combustion with GE dry low NO_x combustors. During FOF operation (which will be limited to a maximum of 2,000 hours per year), NO_x emissions will be controlled by use of water injection to reduce peak flame temperature. Sulfur dioxide (SO_2) and sulfuric acid mist (H_2SO_4) emissions will be controlled through the use of natural gas and by limiting the use of low sulfur fuel oil to no more than 2,000 hours per year. Carbon monoxide (CO), volatile organic compounds (VOCs) and particulate matter (PM) emissions will be controlled through good combustion practices. PM emissions will be further reduced by filtering the combustion air. Trace metal emissions (i.e., lead (Pb), beryllium (Be), arsenic (As), mercury (Hg)) will result in ambient impacts below the FDEP's draft "No Threat Levels" and applicable ambient standards.

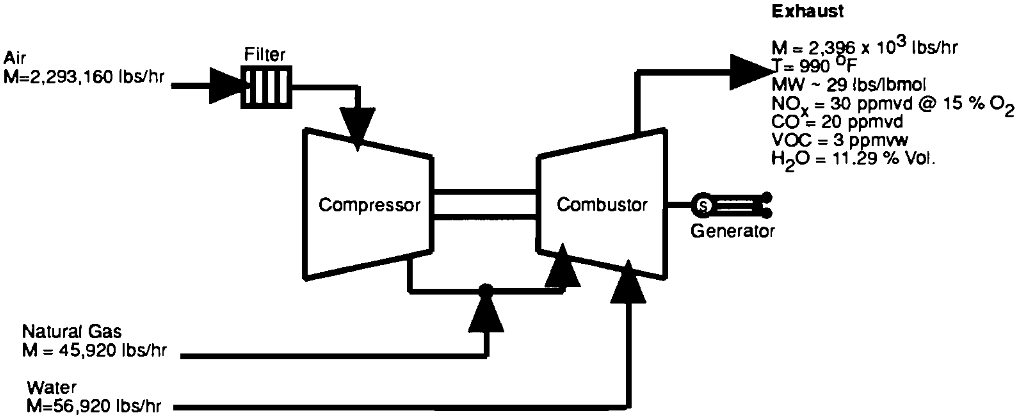
Natural Gas Firing - Dry Low NO_X Combustors

ISO Conditions
100% Load



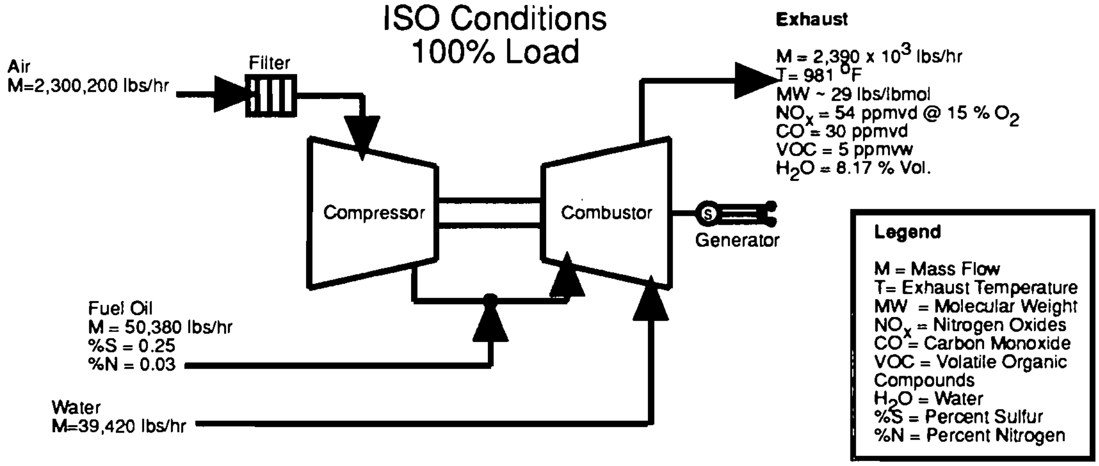
Natural Gas Firing with Power Augmentation - Water Injection

ISO Conditions
100% Load



Fuel Oil Firing - Water Injection

ISO Conditions
100% Load



GRU

SIMPLIFIED
PROCESS FLOW DIAGRAM

Figure 2-1

2.2 PROPOSED SOURCE EMISSIONS AND STACK PARAMETERS

The estimated stack emissions and exhaust parameters that are representative of the advanced CT design (General Electric, 1993) proposed for the project are presented in Tables 2-1 through 2-7 for the nominal 74 MW CT unit. These tables present the natural gas and fuel oil cases for four ambient temperatures: 20°F, 59°F, 75°F and 95°F. GE data sheets which form the basis for these tables are contained in Appendix A. These tables include both regulated criteria air pollutants (NO_2, CO, SO_2, PM_{10}, VOC and Pb) and regulated noncriteria air pollutants. Although a number of these pollutants (primarily the hazardous air pollutants) are no longer subject to PSD review according to EPA's Clean Air Act Transition Guidance (EPA, 1991), it is understood that FDEP will continue to review impacts of those pollutants listed under Title III of the 1990 Clean Air Act Amendments during the PSD review process.

Worst-case air quality impacts due to the proposed facility are a function of emission rate and plume rise. Emission rates and plume rise from all fossil fuel fired power plants are functions of plant load. However, unlike conventional steam generating units, the fuel consumption, emission rates, and plume rise from CTs are also functions of ambient temperature. Although it is not practical to model all possible operating scenarios for the facility, a large number of cases (combinations of operating conditions and fuel types) were examined to represent the range of conditions that will occur during actual operations. The low (20°F) and high (95°F) ambient temperatures are reasonable extreme points selected to indicate the influence of compressor inlet temperature on combustion turbine performance and emissions/exhaust characteristics. It should be recognized, however, that the CT may operate at temperatures outside this range for short periods of time during a given year. The 75°F temperature case represents annual average temperature conditions for the Deerhaven Generating Station, and the 59°F temperature case represents the ISO conditions case. The 60 percent, 80 percent, and 100 percent loads represent the range of loads over which the CT is likely to be operated on both fuels.

A review of the CT design information in Tables 2-1 through 2-7 indicates that highest criteria air pollutant emission rates occur when burning distillate fuel oil. Combustion of natural gas and distillate fuel oil result in similar exhaust gas flow rates and stack exit temperatures, which are directly related to plume rise.

Natural gas is supplied to the site by Florida Gas Transmission. Number 2 (distillate) fuel oil is obtained from various suppliers and is stored in an on-site tank. An existing supply of 387,000 gallons of fuel oil with a sulfur content of 0.25 percent (by weight) is stored in a

TABLE 2-1
SIMPLE CYCLE UNIT
ESTIMATED (1) PERFORMANCE ON NATURAL GAS (100% LOAD)

CONDITIONS				
Ambient Temperature (°F)	20	75	95	ISO (59)
Ambient Relative Humidity (%)	100	90	50	ISO (60)
Elevation (ft) (above MSL)	178	178	178	ISO (0)
Maximum Heat Input Rate (mmBtu/hr)(2)	1,074.5	931.1	868.3	971.1
EMISSIONS (lb/hr)				
Carbon Monoxide	35	31	29	32
Nitrogen Oxides (at 15% O_2) (15 ppmvd)	58	51	47	53
Sulfur Dioxide(3)	29	25	24	26
Particulate Matter (PM_{10})	7	7	7	7
Volatile Organic Compounds (non-methane HC)	3	2.7	2.6	2.8
Lead	Neg.	Neg.	Neg.	Neg.
Asbestos	Neg.	Neg.	Neg.	Neg.
Beryllium	Neg.	Neg.	Neg.	Neg.
Mercury	Neg.	Neg.	Neg.	Neg.
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.
Total Fluorides	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist	3.0	2.6	2.5	2.8
Hydrogen Sulfide	Neg.	Neg.	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.
Benzene	Neg.	Neg.	Neg.	Neg.
Inorganic Arsenic	Neg.	Neg.	Neg.	Neg.
Radionuclides	Neg.	Neg.	Neg.	Neg.
STACK PARAMETERS				
Stack Height (ft)	52	52	52	52
Stack Diameter (ft)	14.1	14.1	14.1	14.1
Stack Gas Temperature (°F)	964	1001	1011	989
Stack Gas Exit Velocity (ft/sec)	160	144	138	149

(1) Emission estimates based on manufacturer's data (GE, 1993).
(2) For CT's the heat input rate is based on the higher heating value of the fuel.
(3) Sulfur dioxide emissions based on 10 grains/100 SCF total sulfur in natural gas.

MSL = Mean sea level
Neg. = Negligible

Source: ENSERCH Environmental, 1994

TABLE 2-2
SIMPLE CYCLE UNIT
ESTIMATED [1] PERFORMANCE ON NATURAL GAS (80% LOAD)

CONDITIONS				
Ambient Temperature (°F)	20	75	95	ISO (59)
Ambient Relative Humidity (%)	100	90	50	ISO (60)
Elevation (ft) (above MSL)	178	178	178	ISO (0)
Maximum Heat Input Rate (mmBtu/hr)[2]	896	792.9	758.8	821.5
EMISSIONS (lb/hr)				
Carbon Monoxide	29	26	24	27
Nitrogen Oxides (at 15% O_2) (15 ppmvd)	49	43	41	44
Sulfur Dioxide[3]	25	21	21	22
Particulate Matter (PM_{10})	7	7	7	7
Volatile Organic Compounds (non-methane HC)	3	2.7	2.6	2.8
Lead	Neg.	Neg.	Neg.	Neg.
Asbestos	Neg.	Neg.	Neg.	Neg.
Beryllium	Neg.	Neg.	Neg.	Neg.
Mercury	Neg.	Neg.	Neg.	Neg.
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.
Total Fluorides	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist	2.5	2.25	2.15	2.33
Hydrogen Sulfide	Neg.	Neg.	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.
Benzene	Neg.	Neg.	Neg.	Neg.
Inorganic Arsenic	Neg.	Neg.	Neg.	Neg.
Radionuclides	Neg.	Neg.	Neg.	Neg.
STACK PARAMETERS				
Stack Height (ft)	52	52	52	52
Stack Diameter (ft)	14.1	14.1	14.1	14.1
Stack Gas Temperature (°F)	988	1037	1058	1022
Stack Gas Exit Velocity (ft/sec)	133	123	120	126

[1] Emission estimates based on manufacturer's data (GE, 1993).
[2] For CT's the heat input rate is based on the higher heating value of the fuel.
[3] Sulfur dioxide emissions based on 10 grains/100 SCF total sulfur in natural gas.

MSL = Mean sea level
Neg. = Negligible

Source: ENSERCH Environmental, 1994

TABLE 2-3
SIMPLE CYCLE UNIT
ESTIMATED (1) PERFORMANCE ON NATURAL GAS (60% LOAD)

CONDITIONS				
Ambient Temperature (°F)	20	75	95	ISO (59)
Ambient Relative Humidity (%)	100	90	50	ISO (60)
Elevation (ft) (above MSL)	178	178	178	ISO (0)
Maximum Heat Input Rate (mmBtu/hr)(2)	760	678.1	649	701.9
EMISSIONS (lb/hr)				
Carbon Monoxide	24	21	35	23
Nitrogen Oxides (at 15% O_2) (15 ppmvd)	41	37	35	38
Sulfur Dioxide(3)	21	18	18	19
Particulate Matter (PM_{10})	7	7	7	7
Volatile Organic Compounds (non-methane HC)	3	2.7	2.6	2.8
Lead	Neg.	Neg.	Neg.	Neg.
Asbestos	Neg.	Neg.	Neg.	Neg.
Beryllium	Neg.	Neg.	Neg.	Neg.
Mercury	Neg.	Neg.	Neg.	Neg.
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.
Total Fluorides	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist	2.2	1.9	1.8	2.0
Hydrogen Sulfide	Neg.	Neg.	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.
Benzene	Neg.	Neg.	Neg.	Neg.
Inorganic Arsenic	Neg.	Neg.	Neg.	Neg.
Radionuclides	Neg.	Neg.	Neg.	Neg.
STACK PARAMETERS				
Stack Height (ft)	52	52	52	52
Stack Diameter (ft)	14.1	14.1	14.1	14.1
Stack Gas Temperature (°F)	1037	1086	1100	1072
Stack Gas Exit Velocity (ft/sec)	104	107	105	118

(1) Emission estimates based on manufacturer's data (GE, 1993).
(2) For CT's the heat input rate is based on the higher heating value of the fuel.
(3) Sulfur dioxide emissions based on 10 grains/100 SCF total sulfur in natural gas.

MSL = Mean sea level
Neg. = Negligible

Source: ENSERCH Environmental, 1994

TABLE 2-4
SIMPLE CYCLE UNIT
ESTIMATED (1) PERFORMANCE ON NATURAL GAS (100% LOAD)
POWER AUGMENTATION MODE

CONDITIONS		
Ambient Temperature (°F)	95	ISO (59)
Ambient Relative Humidity (%)	50	ISO (60)
Elevation (ft) (above MSL)	178	ISO (0)
Maximum Heat Input Rate (mmBtu/hr)(2)	986.1	1096.6
EMISSIONS (lb/hr)		
Carbon Monoxide	38	42
Nitrogen Oxides (at 15% O_2) (30 ppmvd)	107	120
Sulfur Dioxide(3)	27	30
Particulate Matter (PM_{10})	7	7
Volatile Organic Compounds (non-methane HC)	4	4.5
Lead	Neg.	Neg.
Asbestos	Neg.	Neg.
Beryllium	Neg.	Neg.
Mercury	Neg.	Neg.
Vinyl Chloride	Neg.	Neg.
Total Fluorides	Neg.	Neg.
Sulfuric Acid Mist	2.8	3.1
Hydrogen Sulfide	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.
Benzene	Neg.	Neg.
Inorganic Arsenic	Neg.	Neg.
Radionuclides	Neg.	Neg.
STACK PARAMETERS		
Stack Height (ft)	52	52
Stack Diameter (ft)	14.1	14.1
Stack Gas Temperature (°F)	1014	990
Stack Gas Exit Velocity (ft/sec)	142	153

(1) Emission estimates based on manufacturer's data (GE, 1993).

(2) For CT's the heat input rate is based on the higher heating value of the fuel.

(3) Sulfur dioxide emissions based on 10 grains/100 SCF total sulfur in natural gas.

MSL = Mean sea level
Neg. = Negligible

Source: ENSERCH Environmental, 1994

TABLE 2-5
SIMPLE CYCLE UNIT
ESTIMATED (1) PERFORMANCE ON FUEL OIL (100% LOAD)

CONDITIONS				
Ambient Temperature (°F)	20	75	95	ISO (59)
Ambient Relative Humidity (%)	100	90	50	ISO (60)
Elevation (ft) (above MSL)	178	178	178	ISO (0)
Maximum Heat Input Rate (mmBtu/hr)(2)	1,100	938.6	883.7	990.6
EMISSIONS (lb/hr)				
Carbon Monoxide	71	62	59	65
Nitrogen Oxides (at 15% O_2) (54 ppmvd)(3)	237	201	189	213
Sulfur Dioxide(4)	266	227	214	240
Sulfur Dioxide(5)	53	45	43	48
Particulate Matter (PM_{10})	15	15	15	15
Volatile Organic Compounds	7	6	6	6
Lead (6)	0.06380	0.05444	0.05126	0.05746
Asbestos	Neg.	Neg.	Neg.	Neg.
Beryllium (6)	0.00036	0.00031	0.00029	0.00032
Mercury (6)	0.0010	0.00085	0.0008	0.0009
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.
Total Fluorides	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist(4)	28	24	22	25
Sulfuric Acid Mist(5)	5.6	4.8	4.5	5.0
Hydrogen Sulfide	Neg.	Neg.	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.
Benzene	Neg.	Neg.	Neg.	Neg.
Inorganic Arsenic	0.00539	0.004599	0.00433	0.004854
Radionuclides	Neg.	Neg.	Neg.	Neg.
STACK PARAMETERS				
Stack Height (ft)	52	52	52	52
Stack Diameter (ft)	14.1	14.1	14.1	14
Stack Gas Temperature (°F)	955	994	1007	981
Stack Gas Exit Velocity (ft/sec)	162	146	141	152

(1) Emission estimates based on manufacturer's data (GE, 1993).

(2) For CT's the heat input rate is based on the higher heating value of the fuel.

(3) Maximum FBN content = 0.03% = an additional 12ppmvd NO_x above 42 ppmvd.

(4) Sulfur dioxide and sulfuric acid mist based on 0.25% sulfur by weight in the fuel (current fuel oil supply).

(5) Sulfur dioxide and sulfuric acid mist based on 0.05% sulfur by weight in fuel (future fuel oil supply)

(6) Emission estimates from U.S. EPA (1993).

MSL = Mean sea level
Neg. = Negligible

Source: ENSERCH Environmental, 1994

TABLE 2-6

SIMPLE CYCLE UNIT

ESTIMATED (1) PERFORMANCE ON FUEL OIL (80% LOAD)

CONDITIONS				
Ambient Temperature (°F)	20	75	95	ISO (59)
Ambient Relative Humidity (%)	100	90	50	ISO (60)
Elevation (ft) (above MSL)	178	178	178	ISO (0)
Maximum Heat Input Rate (mmBtu/hr)(2)	926	798	755.7	840
EMISSIONS (lb/hr)				
Carbon Monoxide	56	50	48	53
Nitrogen Oxides (at 15% O_2) (54 ppmvd)(3)	197	170	161	179
Sulfur Dioxide(4)	224	193	183	203
Sulfur Dioxide(5)	45	39	37	41
Particulate Matter (PM_{10})	15	15	15	15
Volatile Organic Compounds	6	5	6	6
Lead (6)	0.05371	0.04628	0.043832	0.04872
Asbestos	Neg.	Neg.	Neg.	Neg.
Beryllium (6)	0.00031	0.00026	0.00025	0.00030
Mercury (6)	0.00084	0.00073	0.00069	0.00076
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.
Total Fluorides	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist(4)	23	20	19	21
Sulfuric Acid Mist(5)	4.7	4.0	3.8	4.3
Hydrogen Sulfide	Neg.	Neg.	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.
Benzene	Neg.	Neg.	Neg.	Neg.
Inorganic Arsenic	0.004537	0.00391	0.003703	0.004116
Radionuclides	Neg.	Neg.	Neg.	Neg.
STACK PARAMETERS				
Stack Height (ft)	52	52	52	52
Stack Diameter (ft)	14.1	14.1	14.1	14.1
Stack Gas Temperature (°F)	1001	1050	1058	1042
Stack Gas Exit Velocity (ft/sec)	132	124	120	127

(1) Emission estimates based on manufacturer's data (GE, 1993).

(2) For CT's the heat input rate is based on the higher heating value of the fuel.

(3) Maximum FBN content = 0.03% = an additional 12ppmvd NO_x above 42 ppmvd.

(4) Sulfur dioxide and sulfuric acid mist based on 0.25% sulfur by weight in the fuel (current fuel oil supply).

(5) Sulfur dioxide and sulfuric acid mist based on 0.05% sulfur by weight in fuel (future fuel oil supply)

(6) Emission estimates from U.S. EPA (1993).

MSL = Mean sea level
Neg. = Negligible

Source: ENSERCH Environmental, 1994

TABLE 2-7
SIMPLE CYCLE UNIT
ESTIMATED (1) PERFORMANCE ON FUEL OIL (60% LOAD)

CONDITIONS				
Ambient Temperature (°F)	20	75	95	ISO (59)
Ambient Relative Humidity (%)	100	90	50	ISO (60)
Elevation (ft) (above MSL)	178	178	178	ISO (0)
Maximum Heat Input Rate (mmBtu/hr)[2]	782.9	680	646.1	714
EMISSIONS (lb/hr)				
Carbon Monoxide (40 ppm)	63	58	56	60
Nitrogen Oxides (at 15% O_2) (54 ppmvd)[3]	166	144	137	151
Sulfur Dioxide[4]	189	164	156	173
Sulfur Dioxide[5]	38	33	31	35
Particulate Matter (PM_{10})	15	15	15	15
Volatile Organic Compounds	5	5	9	9
Lead [6]	0.04541	0.03944	0.03747	0.04141
Asbestos	Neg.	Neg.	Neg.	Neg.
Beryllium [6]	0.00026	0.00022	0.00021	0.00024
Mercury [6]	0.00071	0.00062	0.00059	0.00065
Vinyl Chloride	Neg.	Neg.	Neg.	Neg.
Total Fluorides	Neg.	Neg.	Neg.	Neg.
Sulfuric Acid Mist[4]	20	17	16	18
Sulfuric Acid Mist[5]	4.0	3.4	3.3	3.6
Hydrogen Sulfide	Neg.	Neg.	Neg.	Neg.
Total Reduced Sulfur	Neg.	Neg.	Neg.	Neg.
Benzene	Neg.	Neg.	NEg.	Neg.
Inorganic	0.003836	0.003332	0.003166	0.003499
Radionuclides	Neg.	Neg.	Neg.	Neg.
STACK PARAMETERS				
Stack Height (ft)	52	52	52	52
Stack Diameter (ft)	14.1	14.1	14.1	14.1
Stack Gas Temperature (°F)	1068	1086	1092	1080
Stack Gas Exit Velocity (ft/sec)	162	146	141	111

[1] Emission estimates based on manufacturer's data (GE, 1993).

[2] For CT's the heat input rate is based on the higher heating value of the fuel.

[3] Maximum FBN content = 0.03% = an additional 12ppmvd NO_x above 42 ppmvd.

[4] Sulfur dioxide and sulfuric acid mist based on 0.25% sulfur by weight in the fuel (current fuel oil supply).

[5] Sulfur dioxide and sulfuric acid mist based on 0.05% sulfur by weight in fuel (future fuel oil supply)

[6] Emission estimates from U.S. EPA (1993).

MSL = Mean sea level
Neg. = Negligible

Source: ENSERCH Environmental, 1994

tank near the proposed CT and is used for light-off oil for the two steam units and as the secondary fuel for DHCT1 and DHCT2. Future distillate fuel oil purchases for the Deerhaven Site will be of the very low sulfur (0.05%) type required by the Clean Air Act Amendments of 1990 for transportation fuel. A limit of .03% fuel bound nitrogen (FBN) was requested after talking with various fuel oil suppliers and finding the range to be .01% to over .03%. Most suppliers felt distillate fuel oil could be supplied with an FBN between .01 and .03%. GRU will make every effort to procure the lowest economical FBN levels in future distillate fuel oil purchases. Typical fuel analyses for natural gas and for low sulfur distillate fuel oil are presented in Tables 2-8 and 2-9, respectively.

TABLE 2-8
TYPICAL NATURAL GAS ANALYSIS

Analysis	Mole (%)
Carbon Dioxide	0.74
Ethane	2.7
Methane	95.8
Nitrogen	0.48
Propane	0.16
Other	0.12
Total:	100.00
Specific Gravity (air at 1)	0.71
Quality Information	**Parameters**
Heating Value (LHV)	21,175.8 Btu/lb
Total Sulfur (Maximum)	10 grains/100 SCF

Source: Ebasco, 1993

TABLE 2-9
TYPICAL FUEL OIL ANALYSIS

Distillate Oil	Weight (Percent)
Carbon	86
Hydrogen	12
Nitrogen	0.015(1)
Oxygen	1
Sulfur	0.035(1)
Ash	0.04

Lower Heating Value: 18,550 Btu/lb
Higher Heating Value: 19,200 Btu/lb

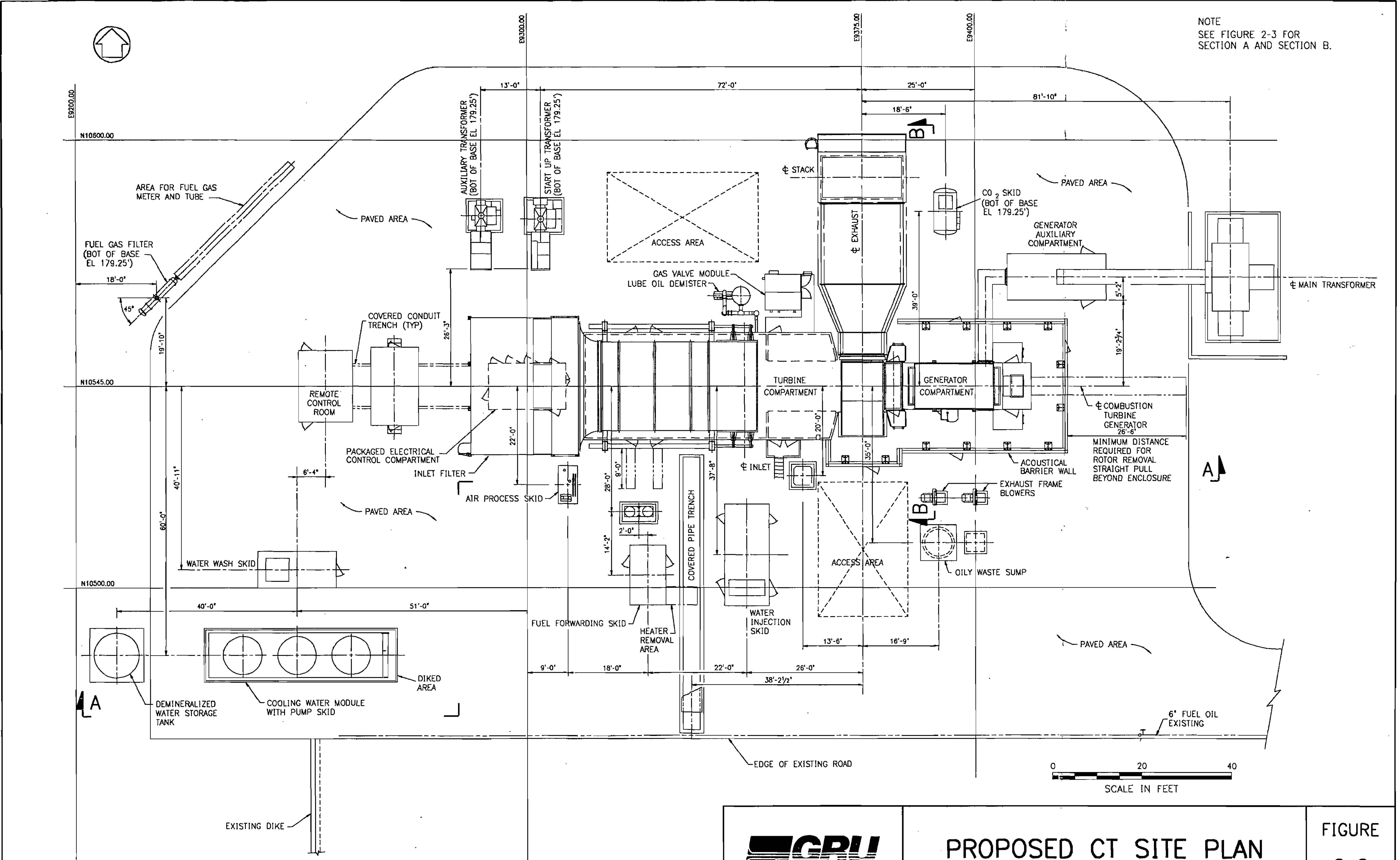
(1) GRU, 1994

Source: Ebasco, 1993

2.3 SITE LAYOUT AND STRUCTURES

Figure 2-2 contains the site plan depicting the proposed CT. Figure 2-3 depicts the profile of the proposed CT.

NOTE
SEE FIGURE 2-3 FOR SECTION A AND SECTION B.



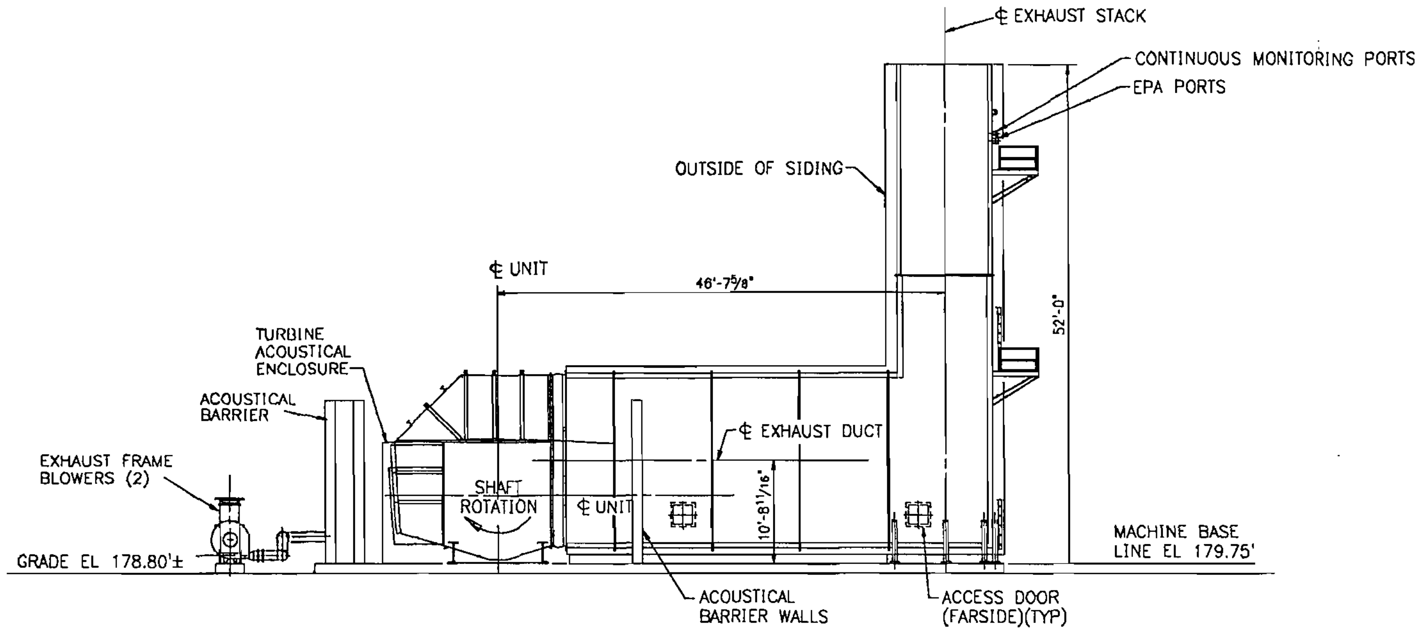
SOURCE: EBASCO SERVICES INCORPORATED, 1994

GRU

PROPOSED CT SITE PLAN

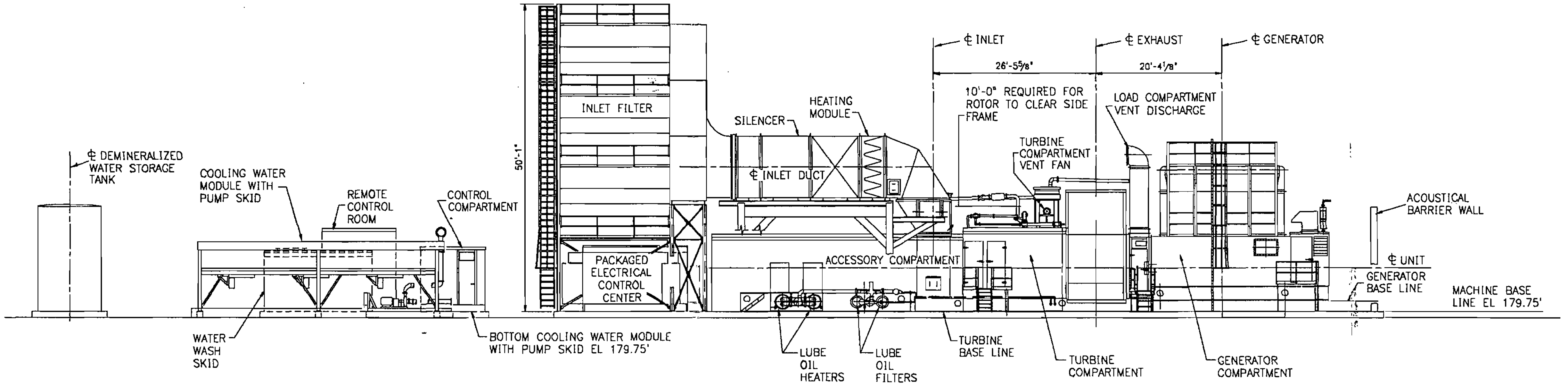
FIGURE
2-2

PLOT DATE FEBRUARY 25, 1994 FILENAME C:\GRU-4124\FIG-2-2.DWG



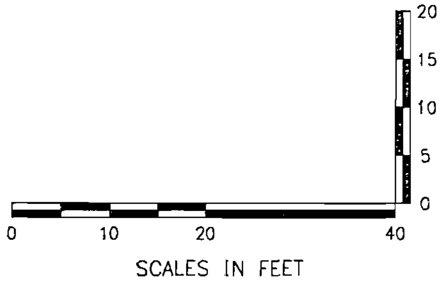
SECTION B

FIGURE 2-2



SECTION A

FIGURE 2-2



GRU

PROPOSED CT SITE PROFILE

FIGURE 2-3

SOURCE: EBASCO SERVICES INCORPORATED, 1994

PLOT DATE FEBRUARY 25, 1994 FILENAME C:\GRU-4124\FIG-2-3.DWG

Section III

3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to the project. These regulations must be satisfied before the proposed facility can be constructed and begin operation.

3.1 NATIONAL AND FLORIDA AMBIENT AIR QUALITY STANDARDS (NAAQS/FAAQS)

The applicable federal (NAAQS) and state (FAAQS) ambient air quality standards are presented in Table 3-1 (PSD increments are also presented in Table 3-1, but discussed in Section 3.2.2). These ambient air quality standards have been promulgated for six pollutants, known as the "criteria" pollutants: NO_2, CO, SO_2, PM_{10}, VOC, and Pb. The primary NAAQS/FAAQS were promulgated to protect the public health, and the secondary NAAQS/FAAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Alachua County is an "attainment" area for all criteria pollutants, meaning that existing concentrations are within the allowable primary and secondary standards.

3.2 PSD REVIEW REQUIREMENTS

3.2.1 General Requirements

Under the federal and FDEP PSD permit review requirements, all major new or modified existing sources of air pollutants located in attainment areas and regulated under the Clean Air Act (CAA) must be reviewed and approved. A "major stationary source" is defined as any one of 28 specified source categories which has the potential to emit 100 tons per year (TPY) or more, or any other stationary source which has the potential to emit 250 TPY or more of any air pollutant regulated under the CAA. Fossil fuel-fired steam electric plants of more than 250 mmBtu/hr of heat input comprise one of the 28 specified source categories. Thus, the existing Deerhaven Generating Station's steam units are subject to the 100 TPY cutoff. The term "potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment. The emissions from the existing units exceed the 100 TPY criteria. Therefore, the Deerhaven Generating Station is considered a major stationary source. Sources are considered major modifications if they will increase the potential to emit by more than the PSD significant emission rates listed in Table 3-2. The

TABLE 3-1
AMBIENT AIR QUALITY STANDARDS AND PSD INCREMENTS

Pollutant	Averaging Time	Federal NAAQS ($\mu g/m^3$)	Florida FAAQS ($\mu g/m^3$)	Class I PSD Increment ($\mu g/m^3$)	Class II PSD Increment ($\mu g/m^3$)
CO	1-hour	40,000	40,000	N/A	N/A
	8-hour	10,000	10,000	N/A	N/A
NO_2	Annual	100	100	2.5	25
SO_2	3-hour	1,300 (1)	1,300 (1)	25	512
	24-hour	365	260	5	91
	Annual	80	60	2	20
PM (2)	24-hour	150	150	10 (8)	37 (30)
	Annual	50	50	5 (4)	19 (17)
O_3 (3)	1-hour	235	235	N/A	N/A
Pb	Calendar Quarter	1.5	1.5	N/A	N/A

(1) The 3-hour average SO_2 ambient air quality standard is a secondary (welfare-related) standard. All of the other federal and Florida ambient air quality standards are primary (health-related) standards.

(2) Ambient air quality standards are based on PM_{10} and PSD increments are based on total suspended particulates (TSP) until June 3, 1994 when the PM_{10} PSD increment recently promulgated becomes effective. The new PSD increments will be 8 $\mu g/m^3$ (24-hr) and 4 $\mu g/m^3$ (annual) for Class I areas and 30 $\mu g/m^3$ (24-hr) and 17 $\mu g/m^3$ (annual) for Class II areas.

(3) Ozone values are associated with emissions of VOCs and NO_x.

Note: Short-term standards (i.e., those with averaging times less than annual) and increments can be exceeded once per year.

N/A = No PSD increments exist for these pollutants.
$\mu g/m^3$ = micrograms per cubic meter

Sources: 40 CFR 50; F.A.C. 17-272.300; F.A.C. 17-272.500; Federal Register Vol. 58 No. 105, June 3, 1993, p. 31,621 - 31,638.

TABLE 3-2
PSD SIGNIFICANT EMISSION RATES

Pollutant	Annual Significant Emission Rate (TPY)
Carbon Monoxide	100
Nitrogen Oxides	40
Sulfur Dioxide	40
Particulate Matter (PM_{10})	15
Total Suspended Particulates (TSP)	25
Volatile Organic Compounds	40
Lead	0.6
Asbestos	0.007
Beryllium	0.0004
Mercury	0.1
Vinyl Chloride	1
Total Fluorides	3
Sulfuric Acid Mist	7
Reduced Sulfur Compounds (Including H_2S)	10
Total Reduced Sulfur (Including H_2S)	10

TPY = tons per year

Source: F.A.C. 17-212.400 Table 212.400-2 emissions from the proposed CT will exceed the PSD significant emission rates for some pollutants and thus subject the project to PSD review.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified source located in an attainment area. The PSD regulations are contained in Ch.17-212.400 F.A.C. Major sources and modifications are required to undergo the following analyses under PSD for each air pollutant emitted in significant quantities:

- A control technology analysis;
- An air quality impacts analysis; and
- An additional impacts analysis.

In addition to these analyses, a new source must also be reviewed with respect to Good Engineering Practice (GEP) stack height regulations (EPA, 1985a), New Source Performance Standards (NSPS), and any state emission standards.

3.2.2 PSD Increments/Classifications

In promulgating the 1977 Clean Air Act (CAA) Amendments, Public Law 95-95, Congress specified that certain increases above an air quality "baseline concentration" level for SO_2 and TSP concentrations would constitute "significant deterioration." The magnitudes of the allowable increases, or "increments," depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications were designated based on criteria established in the CAA Amendments of 1977. Initially, Congress designated PSD areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would allow greater deterioration than Class II areas, were designated. EPA subsequently incorporated the requirements for classifications and area designations into the PSD regulations.

On October 17, 1988, the EPA promulgated regulations to prevent significant deterioration due to NO_x emissions and established PSD increments for NO_2 concentrations. On June 3, 1993, EPA promulgated regulations which revised the PSD increments for particulate matter from TSP to PM_{10}. This change is to become effective on June 3, 1994. The allowable PSD increments for SO_2, TSP, PM_{10}, and NO_2 were presented in Table 3-1. The FDEP has adopted the EPA PSD classification scheme and the allowable PSD increments for SO_2, TSP, and NO_2. It is assumed that the EPA PSD increment for PM_{10} will be adopted by FDEP as well.

The term "baseline concentration" is derived from federal and state PSD regulations and denotes a concentration level corresponding to a specified baseline date and contributions from certain additional baseline sources. The PSD regulations (Ch. 17-212.200 F.A.C.) define baseline concentration as the ambient concentration level which is predicted to exist in the baseline area at the time of the applicable minor source baseline date. Emission increases after the baseline date consume PSD increments. A baseline concentration is determined for each pollutant for which PSD increments are promulgated and a baseline date is established. The baseline concentration includes:

1. The actual emissions representative of sources in existence on the applicable baseline date; and
2. The allowable emissions of major stationary sources which commenced construction before January 6, 1975, for SO_2 and TSP (now PM_{10}) concentrations, or before February 8, 1988, for NO_2 concentrations, but which were not in operation by the applicable baseline date.

3.2.3 Control Technology Review

The control technology review requirements of the PSD regulations require that all applicable federal and state emission limiting standards be met and that best available control technology (BACT) be applied to control emissions from the source. The BACT requirements apply to all applicable regulated and unregulated air pollutants for which the increase in emissions from the source or modification exceeds the PSD significant emission rates in Table 3-2.

BACT is defined in Ch. 17-212.200 F.A.C. as:

> An emission limitation, including a visible emissions standard, based on the maximum degree of reduction of each pollutant emitted which the Department, on a case by case basis, taking into account energy, environmental and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of each such pollutant.
>
> If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or

> facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice or operation.
>
> Each BACT determination shall include applicable test methods or shall provide for determining compliance with the standard(s) by means which achieve equivalent results.

The requirements for BACT were incorporated within the PSD framework in the 1977 CAA Amendments. The primary purpose of BACT is to minimize consumption of PSD increments and thereby increase the potential for future economic growth without significantly degrading air quality. Guidelines for the evaluation of BACT can be found in the draft *New Source Review Workshop Manual* (EPA, 1990a) and the draft *Top-Down BACT Guidance Document* (EPA, 1990c). These guidelines were issued by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. Although the "top-down" approach to BACT has been suspended by EPA as a result of a suit settlement until formal rulemaking is undertaken, FDEP is still requesting that this approach to BACT be used. BACT is determined on a case-by-case basis, and BACT for a source in one area may not be the same for an identical source located in another area. BACT analyses for the same types of emissions units and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors.

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, at a minimum, demonstrate compliance with the applicable New Source Performance Standards (NSPS). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A determination of BACT is to be based on sound judgement, balancing environmental benefits with energy, economic, and other impacts.

3.2.4 Ambient Air Quality Monitoring Requirements

In accordance with the requirements of Ch.17-212.400(5)(f) F.A.C., any application for a PSD permit must contain an analysis of continuous ambient air quality monitoring data in the area affected by the proposed major stationary source or major modification.

According to EPA's *Ambient Monitoring Guidelines for Prevention of Significant Deterioration* (EPA, 1987), ambient air monitoring for a period of up to one year is generally appropriate to satisfy the PSD monitoring requirements. A minimum of four months of data are generally required. Existing data from the vicinity of the proposed source may be utilized if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered.

The PSD regulations include an exemption in Ch.17-212.400(3)(e) which states that the Department may exempt a proposed major stationary source or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the source or modification would cause, in any area, air quality impacts less than the *de minimis* air quality impact levels presented in Table 3-3.

3.2.5 Source Impact Analysis

A source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the PSD significant emission rate. The PSD regulations specifically require the use of atmospheric dispersion models in performing air quality impact analysis, estimating baseline and future air quality levels, and determining compliance with NAAQS/FAAQS and allowable PSD increments. Reference EPA models must normally be used in performing the impact analysis. Use of nonreference EPA models requires regulatory agency consultation and prior approval. Guidance for the regulatory application of dispersion models is presented in the U.S. EPA *Guideline on Air Quality Models (Revised)* (EPA, 1993a).

3.2.6 Additional Impacts Analysis

In addition to air quality impact analyses, the PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source. These analyses are to be conducted primarily for nearby PSD Class I

TABLE 3-3
PSD *DE MINIMIS* AMBIENT AIR QUALITY IMPACT LEVELS

Pollutant	**Air Quality Impact *De Minimis* Level ($\mu g/m^3$) and Averaging Time** (1)
Carbon Monoxide	575 (8-hour)
Nitrogen Dioxide	14 (Annual)
Sulfur Dioxide	13 (24-hour)
Particulate Matter (PM_{10})	10 (24-hour)
Particulate Matter (TSP)	10 (24-hour)
Volatile Organic Compounds (Ozone)	(2)
Lead	0.1 (3-month)
Beryllium	0.001 (24-hour)
Mercury	0.25 (24-hour)
Vinyl Chloride	15 (24-hour)
Total Fluorides	0.25 (24-hour)
Hydrogen Sulfide	0.2 (1-hour)

(1) Ambient air quality monitoring requirements for applicable pollutants may be exempted if the impact of the net increase in emissions is below the applicable air quality impact *de minimis* levels.

(2) No specific air quality impact *de minimis* level is prescribed for ozone. Exemptions are granted when a proposed source's VOC emissions are less than 100 tons/year.

Source: F.A.C. 17-212.400 Table 212.400-3 areas. Impacts on air quality due to general commercial, residential, industrial, and other growth related activities associated with the source must also be addressed. These analyses are required for each pollutant emitted in significant quantities.

3.3 OTHER REQUIREMENTS

In addition to the requirements of the PSD program, any new or modified source of air pollution must be reviewed with respect to the Good Engineering Practice (GEP) stack height regulations (Ch.17-210.550 F.A.C.), the federal NSPS requirements, and any state-specific emission standards.

3.3.1 Good Engineering Practice (GEP) Stack Height

The 1977 CAA Amendments require under Section 123 that the degree of emission limitation required for control of any air pollutant not be affected by a stack height that exceeds GEP, or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). FDEP has incorporated these rules into Ch.17-210.550 F.A.C.

The EPA's final stack height regulations define GEP stack height for stacks constructed after January 12, 1979, as the greater of:

(1) 65 meters, measured from the ground-level elevation at the base of the stack; or

(2) $H_g = H + 1.5 L$

where:

H_g = GEP stack height, measured from the ground-level elevation at the base of the stack;

H = Height of nearby structure(s) measured from the ground-level elevation at the base of the stack; and

L = Lesser dimension, height or projected width of nearby structure(s).

The term "nearby" is defined by the GEP stack height regulations as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 km. Although GEP stack height regulations require that the stack height credit used in modelling for determining compliance with NAAQS/FAAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater. In this case the proposed stack for the 74 MW generating unit is 52.0 feet (15.8 meters) above ground level. GEP stack height as determined by the "GEP" program (Bowman, 1993) is estimated at 125 feet (38 meters). Thus, the proposed stack height is within the allowable limits.

3.3.2 New Source Performance Standards (NSPS)

The CAA required the U.S. EPA to adopt standards of performance for new or modified stationary sources of air pollution. To date, the U.S. EPA has adopted regulations for approximately 60 stationary source categories. These regulations are contained in 40 CFR Part 60, and incorporated by reference in Ch.17-296.800 F.A.C. The CT is subject to a specific NSPS (Subpart GG). Any source subject to a specific NSPS is also subject to the general provisions of 40 CFR 60 Subpart A.

3.3.2.1 General Provisions

The general provisions of the NSPS regulations are found in 40 CFR 60 Subpart A. The general provisions specify the notification and recordkeeping requirements (40 CFR 60.7), compliance with standards and maintenance requirements (40 CFR 60.11), and the monitoring requirements (40 CFR 60.13) for each affected source.

3.3.2.2 Combustion Turbine Units

In general, CT units are covered in 40 CFR 60, Subpart GG - Standards of Performance for Stationary Gas Turbines which establishes emission limitations on both NO_x and SO_2. The NO_x emission limitation is set by the following equation:

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

where:

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

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

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

Fuel-bound nitrogen (percent by weight)	**F (NO_x percent by volume)**
$N<0.015$	0
$0.015<N<0.1$	$0.04(N)$
$0.1<N<0.25$	$0.004 + 0.0067(N-0.1)$
$N>0.25$	0.005

where:

N = the nitrogen content of the fuel (percent by weight).

Use of the equation results in emission limitations of 98.5, 94.4 and 105.8 parts per million on a dry volume basis (ppmvd) at 15 percent oxygen for the proposed unit when fired on natural gas, natural gas firing with power augmentation and fuel oil, respectively. The SO_2 emission limitations are set at 150 ppmvd corrected to 15 percent oxygen in the exhaust stream or a fuel sulfur content less than or equal to 0.8 percent by weight.

3.3.2.3 Excess Emissions

The EPA has adopted general and specific recordkeeping and reporting requirements relating to excess emissions in 40 CFR 60.7(b) and 40 CFR 60.334(c). The EPA requirements specify maintaining records and submittal of a quarterly report (calendar year) on excess emissions associated with start-ups, shutdowns, malfunctions, inoperative continuous emission monitoring systems, low water-to-fuel ratio, and fuel sulfur content greater than 0.8% by weight. The reporting requirement includes submittal of the quarterly report even when no excess emissions occur. EPA has not adopted any specific limits on the number of hours excess emissions are allowed during start-up, shut down or malfunctions from combustion turbine units regulated under 40 CFR Part 60 Subpart GG.

3.3.3 State-Specific and General Emission Standards

In addition to federal requirements, FDEP has adopted specific and general emission limiting and performance standards. These standards may be found in Ch.17-296 F.A.C. The requirements of these standards must be met along with any federal PSD or NSPS limitation or requirement.

3.3.3.1 General Emission Standards

The FDEP has adopted general particulate matter emission limits (Ch.17-296.310 F.A.C.) as well as general pollutant emission limits (Ch.17-2.620 F.A.C.). These limits apply when no specific emission standard is applicable. For the CT, a general opacity limit of not greater than or equal to 20 percent opacity applies as well as a prohibition on emitting air pollutants that cause or contribute to an objectionable odor.

3.3.3.2 Combustion Turbine Units

The FDEP has not adopted any state-specific emission standards in Rules 17-296 or 17-2.650 F.A.C. relating to the operation of a CT unit. The FDEP has adopted the NSPS requirements of Subparts A and GG by reference in Ch.17-296.800 F.A.C. Based on the current FDEP rules, the CT unit must meet the NSPS requirements as discussed in Section 3.3.2.2.

3.3.3.3 Excess Emissions

The FDEP has adopted standards relating to excess emissions in Ch.17-210.700 F.A.C. The rule allows excess emissions resulting from startup, shutdown, or malfunction of any source as long as best operational practices are applied and the excess emissions do not exceed two hours in any 24-hour period unless authorized by FDEP. The FDEP can authorize different excess emission parameters from other sources on a case-by-case basis.

3.4 SOURCE APPLICABILITY

3.4.1 Nonattainment Applicability

The PSD regulations apply to the proposed project due to the attainment status for Alachua County with respect to all criteria air pollutants. Further, the project site is not within 50 km of any designated nonattainment areas and is therefore not within the "area of influence" of any nonattainment area. Therefore, no nonattainment area rules apply to the proposed CT.

3.4.2 PSD Classification

Alachua County and the surrounding counties are designated as PSD Class II areas for SO_2, PM_{10}, and NO_2. The Deerhaven Generating Station is located approximately 90 km south of the Okefenokee National Wilderness Area and 110 km north-northeast of the Chassahowitzka Wilderness Area, the nearest PSD Class I areas. The Wilderness Areas are those portions of the National Wildlife Refuges which have been officially designated as wilderness.

3.4.3 Pollutant Applicability

Pollutant applicability for the proposed facilities is addressed in Sections 2.0 and 4.0 and briefly summarized here. The proposed project is considered to be a major modification of a major existing source under the PSD regulations. PSD review is required for any regulated pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 3-2. As shown in Table 3-4, the potential emissions for the proposed facilities will exceed the PSD significant emission rates for the following regulated pollutants: NO_x, SO_2, PM_{10}, and H_2SO_4. The proposed project is subject to PSD review for only these pollutants.

3.4.4 Ambient Air Quality Monitoring

Based upon the net increase in emissions from the proposed facility presented in Table 3-4, a PSD preconstruction ambient air monitoring analysis is required, as part of the air quality impact analysis for NO_2, SO_2, PM_{10}, and H_2SO_4. However, if the net increase in a source's impact of a pollutant is less than the *de minimis* air quality impact level, as shown in Table 3-3, then an exemption from the preconstruction ambient air quality monitoring requirement may be granted for that pollutant. In addition, if an acceptable ambient air monitoring method for the pollutant has not been established by EPA, monitoring is not required.

Prior to commencement of preconstruction ambient air quality monitoring, preliminary modelling was conducted to indicate those pollutants which could be exempted from the monitoring requirement. As verified by the revised modelling analysis described in Sections 6.0 and 7.0, the increases in air quality impacts for NO_2, SO_2, and PM_{10} are predicted to fall

TABLE 3-4
MAXIMUM POTENTIAL ANNUAL EMISSIONS (SIMPLE CYCLE UNIT) AND PSD SIGNIFICANCE VALUES

Pollutant	Emissions[1] (TPY)	PSD Significant Emission Rate (TPY)	PSD Review Required (Yes/No)
Carbon Monoxide	97.35	100	No
Nitrogen Oxides	276.42	40	Yes
Sulfur Dioxide (0.25% S)[2]	265.2	40	Yes
Sulfur Dioxide (0.05% S)[2]	73.57	40	Yes
Particulate Matter (PM_{10})	21.65	15	Yes
Total Suspended Particulates (TSP)	21.65	25	No
Volatile Organic Compounds	8.99	40	No
Lead[3]	0.058	0.6	No
Asbestos	Neg.	0.007	No
Beryllium[3]	0.00033	0.0004	No
Mercury[3]	0.0009	0.1	No
Vinyl Chloride	Neg.	1	No
Total Fluorides	Neg.	3	No
Sulfuric Acid Mist (0.25% S)[2]	23.94	7	Yes
Sulfuric Acid Mist (0.05% S)[2]	7.7	7	Yes
Hydrogen Sulfide	Neg.	10	No
Total Reduced Sulfur	Neg.	10	No

(1) Full-load operation; 59°F temperature (ISO conditions); 2,000 hours on fuel oil, 1,510 hours on gas, and 390 hours on gas with power augmentation.
(2) Emission estimates based on a maximum distillate fuel oil sulfur content of 0.05 and 0.25 percent.
(3) Based on AP-42, Section 3.1, Table 3.1-7(EPA, 1993).

Neg. = Negligible
TPY = Tons per year

Source: ENSERCH Environmental, 1994

below the *de minimis* impact levels presented in Table 3-3. There are no EPA approved PSD protocol ambient monitoring methods for H_2SO_4. Therefore, monitoring is not required for NO_2, SO_2, PM_{10}, or H_2SO_4.

Section IV

4.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

4.1 INTRODUCTION

The project's potential annual emissions of the pollutants regulated under the PSD program and the associated PSD significant emission rates are presented in Table 3-4. As noted, the following pollutants will be emitted in quantities greater than the PSD significant emission rates and thus are subject to BACT:

- Nitrogen Oxides (NO_x)
- Sulfur Dioxide (SO_2)
- Sulfuric Acid Mist (H_2SO_4)
- Particulate Matter (PM_{10})

This BACT analysis addresses the control strategies and costs associated with achieving the most stringent emission levels currently being imposed by the regulatory agencies on similar projects. The BACT analysis also examines effects of control strategies on other pollutants not subject to BACT which are either considered hazardous air pollutants or emitted in *de minimis* quantities.

4.2 BACT PROCEDURES

When conducting a BACT analysis, a permit applicant is required to follow the procedures and guidelines established by the EPA as well as any requirements set by the State/Local regulatory agencies. Most of the EPA procedures and guidelines have been documented in recent publications and include:

- *"Draft Top-Down BACT Summary"* (EPA, 1990c),
- *"OAQPS Control Cost Manual, Fourth Edition"* (EPA, 1990d),
- *"New Source Review Workshop Manual"* (EPA, 1990a), and
- *"Alternative Control Techniques Document (ACT)* (EPA, 1993b).

Currently the EPA is not requiring applicants to follow the Top-Down BACT procedures since the agency is in litigation on their use. However, FDEP, which is the permitting authority in this case, is requiring applicants to follow these procedures. As such, this BACT analysis follows the Top-Down BACT procedures.

The first step in a top down BACT analysis is the identification of the most stringent emission limitation(s) being applied to similar projects. These most stringent emission limitations, normally considered to be the lowest achievable emission rate (LAER), are then treated as BACT unless the applicant can demonstrate that meeting these emission limitations is either technically infeasible or of unreasonable cost when considering economic, energy and environmental factors. Identification of these emission limitations began with a review of the EPA's BACT/LAER Clearinghouse (EPA, 1990b). This review was conducted electronically through direct access to the EPA's Bulletin Board on October 21, 1993. Information was obtained based on two search criteria: process name (turbine) and date inserted (1/1/92). Information on determinations entered prior to the selected insertion date had been collected under previous reviews, dating back to 1985. The analysis continued with the California Air Pollution Control Officer's Association (CAPCOA) BACT Clearinghouse (CARB, 1993). Information on CAPCOA's BACT Clearinghouse is provided to ENSERCH Environmental on a quarterly basis, with the most recent information covering activities through November 1993. The CAPCOA's BACT Clearinghouse divides gas turbines into two categories; those less than 23 mmBTU/hr of heat input and those greater. The part of the analysis concluded with a review of other technical documents (i.e., manufacturer's data, technical papers...) and recent permits issued by FDEP. The most stringent emission limitations identified are listed in Table 4-1, which contains information on both simple cycle units and combined cycle units.

Following the identification of the most stringent emission limitations, the applicant must determine if the emission source as proposed can meet these limits. If the emission source cannot meet these limitations, additional control options must be examined. If a control option is deemed technically feasible, the applicant must address any economic, energy or environmental impacts associated with the control option. The additional economic impact, expressed in terms of dollars per ton of pollutant controlled (incremental cost) associated with the additional control option must be addressed. The additional energy impact associated with the control option must be examined as well as any environmental impacts. Thus, technically

TABLE 4-1
COMBUSTION TURBINE
MOST STRINGENT EMISSION LIMITATIONS

Pollutant	Combined Cycle		Simple Cycle		Units
	NGF	FOF	NGF	FOF	
NO_X	3.5(1)(2)	11.7(1)(3)	5-8(4)	42(5)	ppmvd @15% O_2 (2), (3), (4), (5)
SO_2	N/A(6)	0.05(7)	N/A(6)	0.05(7)	Fuel %S by weight (5), (6)
PM_{10}/TSP	N/A(8)	N/A(8)	N/A(8)	N/A(8)	N/A(8)
H_2SO_4	N/A(6)	0.05(7)	N/A(6)	0.05)7)	Fuel %S by weight

(1) Used in BACT analysis.
(2) Based on CAPCOA (A330-478-91), with gas firing only, steam injection and SCR.
(3) Based on BACT/LAER Clearinghouse (VA-0161), with steam injection and SCR.
(4) Based on CAPCOA (A330-499-91), high temperature SCR, 5 ppmvd at steady state and 8 ppm during non-steady state conditions.
(5) Based on SD-0001, with water injection
(6) BACT is based on natural gas with 10 grains of total sulfur per 100 standard cubic foot of gas, per meeting with FDEP.
(7) Based on WI-0054, low sulfur fuel oil, 0.05 percent by weight.
(8) Based on good combustion practices.

NGF = Natural gas firing
FOF = Fuel oil firing

Sources: EPA BLIS Bulletin Board (919) 541-5472.
California Air Pollution Control Officer's Association - BACT Clearinghouse.

infeasible options are eliminated and the remaining control options are evaluated. Unreasonably expensive options are eliminated until a BACT level is chosen.

4.3 REQUIREMENTS AND ASSUMPTIONS

This BACT analysis assumes the installation of a nominal 74 MW simple cycle CT manufactured by General Electric (GE), model MS7001EA. The CT will be operated as an intermediate peaking unit for a maximum of 3,900 hours per year. The CT will be capable of operating in any of three modes; natural gas fired (NGF), natural gas fired with power augmentation (NGFPA) or fuel oil firing (FOF). The CT design parameters used in the BACT analysis are presented in Table 4-2. The BACT assumes that the CT will be fired on natural gas as the primary fuel with distillate fuel oil as back-up (a maximum of 2,000 hours per year) and that NGFPA operation will represent less than 10 percent of the total time (i.e. a maximum of 390 hours per year) that the CT is fired on natural gas.

Operation at ISO conditions have been selected for purposes of the BACT analysis. The ISO conditions are slightly cooler than the average annual daily temperature but higher than the annual average low temperature at the site. Use of ISO conditions will allow easy comparison between the proposed BACT emission levels and those of the EPA's New Source Performance Standards (NSPS) for Combustion Turbines (40 CFR 60 Subpart GG). Emission rates estimated by GE at the various operating temperatures, loads and conditions are included in Appendix A as part of this application.

The unit selected is one of GE's Dry Low NO_x CTs designed to minimize NO_x emissions during NGF operation through staged combustion without the aid of water or steam injection. During NGFPA and FOF operations the CT will rely on water injection to control the NO_x emissions. PM_{10} emissions are controlled through good combustion practices as well as pre-filtering of the combustion air. SO_2 and H_2SO_4 emissions are controlled through fuel quality. These control strategies represent the baseline of the potential CT emission estimates.

4.4 NITROGEN OXIDE EMISSIONS

Formation of NO_x in a combustion process follows one of three basic chemical mechanisms. The first mechanism is known as thermal NO_x and occurs through the dissociation and subsequent reaction of the nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. These reactions are favored under conditions of high temperatures and elevated pressures. This mechanism follows the general equations:

TABLE 4-2
COMBUSTION TURBINE DESIGN PARAMETERS(1)

Number of Emission Units:	1
Unit Type	Dry Low NO_x Combustion Turbine
Cycle Type	Simple-Cycle
Service Type	Intermediate Peaking

Parameter	**Fuels**		
	Natural Gas	**Natural Gas with Power Augmentation**	**Fuel Oil**
Output (MW)	82.81	89.58	85.58
Exhaust Temperature (°F)	989	990	981
Heat Rate (BTU/KW HR) (HHV)	11,790	12,300	11,640
Fuel Flow (mmBTU/HR)	971.1	1,096.6	990.6
Fuel Flow (LB/HR)	40,700	45,920	50,380
Maximum Operating Hours(2)	3,900	390	2,000
Emission Rates			
NO_x - Lbs/hr(3)	53	120	213
SO_2 - (0.25% S) Lbs/hr(4)	26	30	240
SO_2 - (0.05% S) Lbs/hr(4)	26	30	48
PM_{10}/TSP - Lbs/hr(5)	7	7	15
H_2SO_4 - (0.25% S) Lbs/hr(6)	2.8	3.1	25
H_2SO_4 - (0.05% S) Lbs/hr(6)	2.8	3.1	5

(1) All data is based on 100 percent load at ISO conditions.

(2) Maximum requested operating times for each of the fuels, with a total combined maximum time operating of 3,900 hrs/yr.

(3) Nitrogen oxide emission rates are based on 15/30/54 ppmvd @ 15 percent oxygen for NGF, NGFPA and FOF, respectively. For FOF the emission reflects a maximum fuel bound nitrogen content of 0.03 percent by weight (42 ppmvd + 12 ppmvd).

(4) Sulfur dioxide emission rates based on a maximum of 10 grains of total sulfur per 100 standard cubic feet of natural gas and a maximum fuel oil sulfur content of 0.25 and 0.05 percent by weight with 95.1 percent conversion of sulfur to SO_2.

(5) Particulate matter emission rates do not include sulfuric acid mist emissions.

(6) Sulfuric acid emission rates based on a 6.5 percent conversion rate of the sulfur in the fuels and a maximum of 10 grains of total sulfur per 100 standard cubic feet of natural gas and a maximum fuel oil sulfur content of 0.25 and 0.05 percent by weight.

Source : ENSERCH Environmental, 1994

Dissociation

$$N_2 \leftrightarrows 2N$$
$$O_2 \leftrightarrows 2O$$

Reaction

$$N_2 + O \rightarrow NO + N$$
$$O_2 + N \rightarrow NO + O$$
$$N + O \rightarrow NO$$

The second mechanism is known as fuel NO_x and occurs through the oxidation of fuel-bound nitrogen during the combustion process. The actual reaction mechanism is quite complex with a variety of possible intermediates. The reaction follows the general equations:

$$H_xC_yN_z + wO_2 \rightarrow (x/2)H_2O + (y)CO_2 + zNO$$
$$H_xC_yN_z + wO_2 \rightarrow (x/2)H_2O + (y)CO_2 + (z/2)N_2$$

The third mechanism is known as prompt NO_x and occurs through the reaction of nitrogen radicals (NO) with the fuel's hydrocarbons (HC) to form intermediates which are further oxidized through the second mechanism. The reaction follows the general equations:

$$NO + C_xHy \rightarrow C_xH_{y-2}N + H_2O$$
$$C_xH_{y-2}N + zO_2 \rightarrow NO + (y-2)/2\ H_2O + xCO_2$$

In order to reduce and control NO_x emissions various technologies focusing on these mechanisms and NO_x chemistry have been used. These control technologies include wet controls, combustion controls and post-combustion controls. Wet controls and combustion controls focus on controlling the production of thermal NO_x by reducing peak flame temperature. Post-combustion controls focus on converting NO_x to N_2 through favorable conditions and mechanisms.

Since control technologies exist which can reduce emissions of NO_x from the CT, the BACT analysis must address their technological feasibility and costs, including consideration of their associated economic, energy and environmental factors associated with meeting the most stringent emission limitations.

4.4.1 Technological Feasibility Analysis

Current control strategies used to reduce and control NO_x emissions include:

- Wet Injection Techniques,
- Dry Low NO_x Combustors, and
- Selective Catalytic Reduction (SCR).

Based on review of the various clearinghouses and recent permits issued by the FDEP the most stringent emission limitations currently being imposed on combined cycle combustion turbines are 3.5 parts per million by volume on a dry basis (ppmvd), corrected to 15 percent oxygen when firing natural gas and 11.7 ppmvd, corrected to 15 percent oxygen when firing distillate fuel oil. Both of these limitations are based on the use of a post combustion control technology.

The following overviews represent the most current information available with respect to combustion turbine control technologies. Only a cursory overview has been provided for wet injection, as this is a well-established, consistently demonstrated technology used for the control of NO_x emissions, and is considered part of the base control technology for this project.

4.4.1.1 Wet Injection Techniques

Wet injection (water or steam injection) has been a proven technology for several years, and is currently used on the majority of the recently manufactured combustion turbines. Water suppression controls NO_x emissions by lowering the flame temperature, which reduces thermal NO_x formation. Water injection technology has had few recent technological advances; however, it continues to be the most effective NO_x suppressor for oil-fired operations. Advanced water injection systems, such as General Electric's multi-nozzle quiet combustor (MNQC), are capable of achieving 25 ppm during gas-fired operation and 42 ppm during oil-fired operation.

4.4.1.2 Dry Low-NO_x Combustors

Dry low-NO_x combustor designs control the fuel and air flows within the combustion zone to minimize thermal NO_x formation by limiting the peak combustion temperature and/or residence time. Fuel staging and air staging within the combustion zone may be used to establish fuel-lean or fuel-rich zones (above or below the stoichiometric amount of combustion air) in order to minimize flame temperatures. Several manufacturers have been involved in the development of dry low-NO_x combustion systems during the last decade.

Dry low-NO_x combustion technology is rapidly becoming the most popular choice for new combustion turbine installations. Several vendors will guarantee turbine emissions of NO_x in the range of 25 ppm to 9 ppm utilizing dry combustion technologies depending upon unit delivery dates. For units in operation, dry low-NO_x combustors can limit NO_x concentrations in natural gas fired turbine exhaust to 25 ppm; oil firing operations on dry low-NO_x combustors limit NO_x emission to 65 ppm without the use of water or steam injection.

Further refinements in dry low-NO_x combustion technology are resulting in predictions of lower NO_x emissions guarantees for future units ranging from 15 ppm to 9 ppm, when firing natural gas. GE has recently indicated that none of their current turbines are designed to meet 15 ppm, but are willing to guarantee a CT which is capable of achieving 15 ppm for delivery after the fourth quarter of 1994. CTs capable of achieving 9 ppm will not be available until about the 1998 time-frame.

4.4.1.3 Selective Catalytic Reduction (SCR)

Selective catalytic reduction (SCR) involves the injection of ammonia into the flue gas stream where it selectively reacts with NO_x in the presence of O_2 and a catalyst to form molecular nitrogen and steam. Because the pertinent reactions normally proceed at temperatures between 1600°F and 2200°F, a catalyst is used to promote the reactions at lower temperatures. Although exact catalyst compositions are proprietary, the use of base metal oxides (vanadium pentoxide, titanium dioxide, or noble metal) for both the active and support materials has been generally acknowledged. The temperature range required for the base metal catalytic reduction process to proceed is typically between 570°F and 750°F. Although some catalyst vendors have guaranteed effective NO_x reduction at higher temperatures, conventional catalyst degradation usually has occurred too rapidly to warrant the use of SCR to control NO_x emissions in higher temperature, simple cycle situations. Review of the information in the clearinghouses indicated no applications of a base metal catalyst on a simple cycle CT.

Recent technological advances in catalyst materials, may allow SCR to be an effective means of NO_x control at the higher temperatures typically encountered in simple cycle CTs. The addition of a zeolite-based catalyst to a conventional SCR system can extend the usually small temperature window required for the reduction reaction to proceed from approximately 570°F - 750°F to approximately 1050°F. In simple cycle units, exhaust gases are typically between 950°F and 1100°F. This is well above the operating temperature window of traditional base metal catalysts. Zeolite catalysts reportedly offer other benefits in addition to efficient NO_x removal at higher operating temperatures. According to the vendors, zeolite catalyst have been shown to have reduced conversion of SO_2 to sulfur trioxide (SO_3) when compared to base metal catalysts and to minimize ammonia slip, both of which will reduce particulate matter emissions due to the formation of ammonia salts in the stack exhaust. They also appear to be less susceptible to poisoning by sulfur-laden exhaust gases. Review of the information in the clearinghouses indicated only two applications of a high temperature zeolite catalyst. The first application was on a combustion turbine at a natural gas pipeline compressor station. The second and more recent application is proposed for three peaking units smaller than the proposed DHCT3. Both of these projects are located in California.

4.4.1.4 Technological Feasibility Summary

The CT selected is designed to use both dry low NO_x combustion technology and water injection to control NO_x emissions during NGF/NGFPA and FOF, respectively. Both of these technologies are considered to be available and technically feasible for this project. However, neither of these technologies will be capable of meeting the most stringent emission limitations identified under Section 4.2. Since the CT cannot meet the most stringent emission limitations with combustion controls alone, an analysis of the addition of a post-combustion control system must be made.

For CTs, the only post-combustion control technology currently available is SCR. For a simple cycle CT, the use of a standard base metal catalyst in the SCR system has been determined to be technically infeasible based on its effective operating temperature range.

The proposed application of the high temperature zeolite catalyst on two California projects required further analysis prior to determining technical feasibility. The first project involves a simple cycle Solar Model H CT fired on natural gas only which will be used to drive two centrifugal base load compressors. This CT is much smaller than the proposed DHCT3 and has a lower exhaust temperature. The second project involves three simple cycle GE Frame 5 CTs which will be used as peaking units. Again, these units are smaller than the proposed

DHCT3 and are expected to have lower exhaust temperatures. To date neither of these units are operational. However, available vendor information indicates that the zeolite catalysts are capable of operating at temperatures as high as 1,100°F. Based on the GE data sheets for the proposed DHCT3, exhaust temperatures will range from 995°F to 1,100°F, depending upon the fuel fired, ambient temperature and load. Since the zeolite catalysts were reported to operate in this temperature range, ENSERCH Environmental investigated the technical feasibility of using such a system. Because the zeolite catalysts are new, only one vendor (Norton Chemical Process Products Corporation, P.O. Box 350, Akron, Ohio 44309-0350) was capable of providing a cost estimate. A second vendor was contacted and a cost estimate requested but no response was received. The initial cost estimate received by ENSERCH Environmental is contained in Appendix B. This cost estimate noted that their current zeolite catalyst is limited to a maximum upper temperature of 1,050°F and that without an air injection system to cool the exhaust gases at the zeolite catalyst, its use would be infeasible. Review of the GE data sheets for the Deerhaven CT confirmed the vendor's exhaust gas temperature findings. However, since the maximum temperature limit of the zeolite catalyst would be reached only occasionally (i.e., loads < 100%), ENSERCH Environmental requested the vendor to revise the initial cost estimate and include the cost of an air injection system. The revised cost estimate is provided in Attachment C.

Based on the information obtained from the vendor, the use of a SCR system equipped with a zeolite catalyst and an air injection system was deemed to be only potentially technically feasible. It was deemed to be only potentially technically feasible based upon its limited usage on simple cycle CTs. In addition, although the concept of an air injection system is easily visualized, its use commercially has been documented only once in the clearinghouses as a commercially available response to the temperature limitations of SCR. Although only potentially technically feasible, ENSERCH Environmental evaluated the impacts of an SCR system equipped with a high temperature zeolite catalyst and an air injection system as the available post-combustion control technology needed to meet the most stringent emission limitations. This control strategy is referred to as Option #1.

A summary of the various control strategy options considered is included in Table 4-3.

4.4.2 Economic Impacts Analysis

The EPA's *Alternative Control Techniques Document (ACT)*, (EPA, 1993b) published in January of 1993 addresses the various control technologies available for use with a CT to reduce NO_x emissions. The ACT also examined the costs associated with the installation and

TABLE 4-3
SIMPLE CYCLE UNIT
NO_x CONTROL TECHNOLOGY FEASIBILITY SUMMARY

Control Strategy	Emission Limits(1)			Feasibility Analysis	Option #
	NGF	NGFPA	FOF		
Dry Low NO_x combustors, water injection and SCR with a base metal catalyst.	3.5	3.5	11.7	Technically infeasible due to the temperature limitations of the base metal catalysts.	N/A
Dry Low NO_x combustors, water injection and SCR with a zeolite catalyst and an air injection system.	3.5	3.5	11.7	Potentially technically feasible. However, only one small CT currently noted as operating in the U.S. Commercial application is currently questionable.	1
Advanced dry low NO_x combustors and water injection	9.0	30	54(2)	Technically infeasible due to the availability of the advanced units (i.e., >1998).	N/A
Dry Low NO_x combustors with water injection	15	30	54(2)	Technically feasible and considered as the base control strategy for this project.	2

(1) Emission limits expressed in terms of parts per million volume on a dry basis (ppmvd) corrected to 15 percent oxygen.

(2) 42 ppmvd plus an allowance for the fuel bound nitrogen up to a maximum of 54 ppmvd corrected to 15 percent oxygen.

NGF = Natural gas firing
NGFPA = Natural gas firing with power augmentation
FOF = Fuel oil firing
N/A = Not applicable (not a feasible option)

Source: ENSERCH Environmental, 1994

operation of these technologies. Because of the comprehensive nature of the ACT document, its costing strategies were used throughout this BACT analysis where applicable.

The ACT has reported cost effectiveness values of \$154/ton for dry low NO_x CTs with NGF and \$575/ton and \$403/ton for water injection associated with NGF and FOF, respectively. Cost effectiveness is expressed in terms of dollars per ton of NO_x removed. The ACT's reported cost effectiveness value for the SCR was \$6,980/ton and was based on meeting a NO_x limitation of 9 ppmvd, corrected to 15 percent oxygen. Since the costs of the dry low NO_x and water injection systems are considered as part of the CT's base package, these costs were not considered in this economic impact analysis. In addition, the ACT's cost effectiveness value for SCR was not used since it does not adequately represent the BACT analysis procedures which must address reducing emissions to those of the most stringent emission limitations (3.5 ppmvd). ENSERCH Environmental's concern regarding the ACT's cost estimate was based on the additional catalyst needed to reduce emissions from the already low CT rates to those of the most stringent emission limitations. Although the emissions reductions were different in the two analyses, the final costs (\$6,672.58/ton) determined for this project did not vary significantly from those of the ACT.

4.4.2.1 Capital Cost Estimate

In developing the capital cost estimate the BACT analysis followed the standard engineering cost estimating procedures outlined in the EPA's *Control Cost Manual* (EPA, 1990d), Gael Ulrich's "*A Guide To Chemical Engineering Process Design And Economics*" (Ulrich, 1984a) and the ACT. The capital cost estimate was based on the vendor quote on the basic equipment. Cost factors for all equipment and operations not covered by the quote, were based on the above references.

The vendor's quote for the GRU DHCT3 included the SCR modules, hot wall reactor housing, ammonia injection grid, ammonia dilution and flow control skid, ammonia storage tank, engineering specifications, continuous monitoring system for ammonia slip and the air injection system for an estimated cost of \$3,279,000. The capital cost factors used to develop the total capital investment (TCI) estimate are presented in Table 4-4 for an SCR system equipped with a zeolite catalyst and an air injection system.

The direct costs associated with the SCR system are the purchased equipment costs (PEC) and direct installation costs (DIC). The PEC includes the SCR and associated auxiliary equipment, instrumentation, sales taxes and freight. The SCR, auxiliary equipment and

TABLE 4-4
SIMPLE CYCLE UNIT
CAPITAL COST FACTORS FOR SELECTIVE CATALYTIC REDUCTION

Cost Item	Factor	Reference
Direct Costs (DC)		
Purchased Equipment Costs (PEC)		
SCR & Auxiliary Equipment	As estimated, A	Vendor quote
Instrumentation	N/A	Vendor quote
State Sales Taxes	N/A	Exempt
Freight	0.05 x A	EPA, 1990d
PEC Subtotal	1.05 x A = B	
Direct Installation Costs (DIC)		
Foundations & Supports	0.08 x B	Ulrich, 1984a
Labor	0.14 x B	EPA, 1990d
Electrical	0.04 x B	EPA, 1990d
Piping	0.04 x B	EPA, 1990d
Insulation	N/A	Vendor quote
Painting	0.01 x B	EPA, 1990d
DIC Subtotal	0.31 x B	
Site Preparation	N/A	Existing site
Buildings	N/A	Existing site
Total DC	**1.31 x B**	
Indirect Costs (IDC)		
Engineering	0.15 x B	Ulrich, 1984a
Construction Overhead	0.05 x B	EPA, 1990d
Contractor Fees	0.10 x B	EPA, 1990d
Contingencies	0.20 x B	GRU/ENSERCH
Start-up	0.02 x B	EPA, 1990d
Performance Testing	0.01 x B	EPA, 1990d
Total IDC	**0.53 x B**	
Total Capital Investment = DC + IDC	**1.84 x B**	

Source: ENSERCH Environmental, 1994

instrumentation were all included in the vendor's quote. The state sales taxes were excluded from the cost analysis since GRU is a tax exempt municipality. Freight charges were assumed to be five percent (EPA, 1990d) of the vendor's quote. The DIC includes foundations and supports, construction labor, electrical, piping, insulation and painting costs. The foundations and supports costs were based on a cost factor of eight percent (Ulrich, 1984a). The labor, piping, electrical and painting costs were based on cost factors of fourteen, four, four and one percent, respectively (EPA, 1990d). Insulation costs were included in the vendor's quote. Site preparation costs and costs associated with additional buildings were neglected since the site is an existing facility.

The indirect costs associated with the SCR system include engineering, construction overhead, contractor fees, contingencies, startup and performance testing costs. For engineering costs a fifteen percent cost factor (Ulrich, 1984a) was used since the zeolite catalyst represents a new technology. Similarly, the contingency cost was set at twenty percent, a value which has been used in other recent BACT analyses involving SCR systems and accepted by FDEP. The construction overhead, contractor fees, startup and performance testing costs were based on cost factors of five, ten, two and one percent, respectively (EPA, 1990d).

The TCI estimation based on the vendor's quote and the above cost factors is presented in Table 4-5. The total estimated cost is approximately 6.3 million dollars or approximately 1.84 times that of the vendor's quote. One reference document indicates that the TCI costs can be expected to be between three and five times (Ulrich, 1984a) the cost of the basic equipment. The EPA documents indicate that costs of 1.26 (EPA, 1993b) and 1.61 (EPA, 1990d) can be expected. Based on the TCI developed from the cost factors, it was determined that the estimate generated by this analysis is reasonable for the project and within good engineering practices.

4.4.2.2 Operating Cost Estimate

The operating cost estimate was based on the data contained in the ACT with cost data adjusted from 1990 dollars to 1993 dollars based on the *Chemical Engineering Plant Cost Index* (August, 1993). The annualized cost figures are based on a 15-year economic life of the SCR system, at an annual interest rate of seven percent.

The operating costs consist of direct and indirect annual costs. The direct annual costs include operating labor, supervisory labor, maintenance labor and materials, catalyst replacement, catalyst disposal, anhydrous ammonia, ammonia dilution system, electricity,

TABLE 4-5
SIMPLE CYCLE UNIT
TOTAL CAPITAL INVESTMENT FOR SELECTIVE CATALYTIC REDUCTION

Cost Item	Estimated Cost (1993$)
Direct Costs (DC)	
Purchased Equipment Costs (PEC)	
SCR & Auxiliary Equipment	$3,279,000.00
Instrumentation	--
State Sales Taxes	--
Freight	163,950.00
PEC Subtotal	$3,442,950.00
Direct Installation Costs (DIC)	
Foundations & Supports	$275,436.00
Labor	482,013.00
Electrical	137,718.00
Piping	137,718.00
Insulation	--
Painting	34,429.50
DIC Subtotal	$1,067,314.50
Site Preparation	--
Buildings	--
Total DC	**$4,510,264.50**
Indirect Costs (IDC)	
Engineering	$516,442.50
Construction Overhead	172,147.50
Contractor Fees	344,295.00
Contingencies	688,590.00
Start-up	68,859.00
Performance Testing	34,429.50
Total IDC	**$1,824,763.50**
Total Capital Investment = DC + IDC	**$6,335,028.00**

Source: ENSERCH Environmental, 1994

performance loss, and air injection system costs. The indirect annual costs include overhead, property taxes, insurance and administration, and capital recovery costs. The capital recovery costs are based on the TCI estimate. The operating cost data are contained in Table 4-6.

Operating and supervisory labor costs were estimated based on 1-hour of operating labor per 8-hour shift for a maximum of 3,900 hours per year at $25.60 per hour (EPA, 1993b) in 1990 dollars. Supervisory labor costs were estimated at 15 percent of the operating labor costs (EPA, 1993b).

Maintenance labor and materials (MLM) costs were estimated (EPA, 1993b) based on the turbine output ($=1,250 X MW + 25,800) in 1990 dollars.

The catalyst replacement costs were estimated based on the vendor's quote of $934,731.00 per layer with an estimated catalyst life of three years or 24,000 hours, whichever comes first. The vendor's quote noted that two layers are required to meet the most stringent emission limitations. The BACT analysis assumed that the catalyst would last five years and that during the economic life of the SCR it would need to be replaced twice.

The catalyst disposal costs were estimated based on a required 8,281 cubic feet (CF) of catalyst with three disposals required over the 15 year period at a cost of $15/CF (EPA, 1993b) in 1990 dollars.

The anhydrous ammonia costs were estimated based on a required 1 to 1 mole ratio of ammonia to NO_x removed by the SCR system plus a ten percent safety/loss factor and ammonia costs of $360/ton in 1990 dollars (EPA, 1993b).

For the ammonia dilution system the annual costs were estimated from a cost factor (EPA, 1993b) based on the amount of ammonia used and a cost of $6 per 1000 pounds of steam needed to vaporize the ammonia, in 1990 dollars.

Electricity costs associated with the ammonia injection system were reportedly small in the ACT and thus ignored. The BACT analysis assumed the same and this cost was neglected. The total performance loss costs were based on a 0.5 percent loss of the units output capacity due to the back pressure associated with the SCR system. This cost is estimated based on lost electrical sales at $0.06/KWH, in 1990 dollars.

TABLE 4-6
DEERHAVEN CT3
OPERATING COST FACTORS/PARAMETERS FOR SELECTIVE CATALYTIC REDUCTION(1)

A. Cost Factors	
Chemical Engineering Plant Cost Index(2):	1990 - 357.6 April 1993 - 358.0
Capital Recovery Factor (CRF)(3):	0.1098
B. Total Capital Investment (TCI)(4), $	$6,335,028.00
C. Direct Annual Costs, $/yr	**Parameter**
1. Operating Labor(4)	= (1hr/8hr-shift) x ($25.60/hr) x (H)
2. Supervisory Labor	= (0.15) x (operating Labor)
3. Maintenance Labor and Materials(4)	= (1,250 x MW + 25,800)
4. Catalyst Replacement(5) (CR)	= (2 layers) x (2 changes) x CR x CRF
5. Catalyst Disposal(4)	= (3 changes) x (8,281 CF/change) x ($15/CF) x CRF
6. Anhydrous Ammonia(4)	= (N) x ($360/ton) x (1.10)
7. Dilution System(4)	= (N) x (.95/.05) x (MW_{H_2O}/MW_{NH_3}) x ($6/1000 lb steam) x (2,000 lb/ton)
8. Electricity	= N/A
9. Performance Loss(4)	= (0.005) x (MW) x ($0.06/KWH) x (1,000 KW/MW) x (H)
10. Blower(6)	= ($0.746Q\Delta Ps\theta p/6356\eta$)
11. Production Loss	= None
D. Indirect Annual Costs, $/yr	**Parameter**
1. Overhead	= (0.6) x (all labor and maintenance material costs)
2. Insurance and Administration	= (0.025) x (TCI)
3. Capital Recovery	= (CRF) x (TCI - CR)

(1) Based on information from the Control Cost Manual (EPA, 1990d) and the ACT (EPA, 1993b).
(2) As published in the *Chemical Engineering* magazine, August, 1993.
(3) Based on 7 percent interest and an economic life of 15 years.
(4) Based on Table 6-8, page 6-20 of the ACT (EPA, 1993b).
(5) Based on the vendor quote.
(6) Based on Equation 2.7, page 2-26 of the Control Cost Manual (EPA,1990d)

CF = cubic feet
N = net reductions of NO_x in tons per year

Source: ENSERCH Environmental, 1994

The air cooling system costs were based on a required air flow of 32,000 SCFM and equation 2.7 of the EPA Control Cost Manual (EPA, 1990d).

The indirect overhead costs were based on the labor and maintenance material costs. A cost factor of 60 percent (EPA, 1993b) was used to estimate this cost.

The insurance and administrative (IA) costs were based on 2.5 percent (EPA, 1993b) of the TCI.

The capital recovery costs were based on the annualized cost of the TCI excluding catalyst costs based on 15 years and a seven percent interest rate.

For this project the total annual costs were estimated at $1,455,957.53 per year. The costs are summarized in Table 4-7.

4.4.3 Energy Impact Analysis

Use of the SCR system, referred to as Option #1, will result in an overall reduction in the CTs' performance and output capacity. The main loss is associated with the additional pressure drop across the ammonia injection grid and the catalyst bed. This pressure drop has been estimated at 4.5 inches of water and can reduce turbine output by as much as 0.5 percent or 1.44 million-kilowatt-hours per year. In addition, energy is also required to pump and store the anhydrous ammonia, run the air injection system and operate the additional process control equipment. Although the losses associated with an SCR are measurable, they are not, by themselves, considered significant enough to warrant rejection of the control strategy.

Use of dry low NO_x combustors and water injection (Option #2) also result in losses. However, these losses are not considered significant and are considered as part of the base package for the CT.

4.4.4 Environmental Impact Analysis

The use of either of the NO_x control technologies (Option #1 or Option #2) will result in additional environmental impacts from the CT. These impacts include higher emission rates for various air pollutants other than NO_x, use of valuable natural resources and increased solid waste disposal requirements.

TABLE 4-7
DEERHAVEN CT3
OPERATING COSTS FOR SELECTIVE CATALYTIC REDUCTION

A. Total Capital Investment, $	$6,335,028.00
B. Direct Annual Costs, $/yr	**Cost**
1. Operating Labor	= 12,466.06
2. Supervisory Labor	= 1,869.91
3. Maintenance Labor and Materials	= 118,167.82
4. Catalyst Replacement	= 410,513.76
5. Catalyst Disposal	= 40,868.70
6. Anhydrous Ammonia	= 31,897.42
7. Dilution System	= 19,455.48
8. Electricity	= N/A
9. Performance Loss	= 86,483.26
10. Blower	= 6,072.00
11. Production Loss	= None
C. Indirect Annual Costs, $/yr	**Cost**
1. Overhead	= 79,502.27
2. Insurance and Administration	= 158,375.70
3. Capital Recovery	= 490,295.14
D. Total Annual Costs, $/yr	**$1,455,957.53**

Source: ENSERCH Environmental, 1994

An SCR system (Option #1) requires the use of ammonia (which is listed by EPA as an extremely hazardous substance). This use presents several problems. The reactions controlling NO_x emissions will not consume all the ammonia injected into the exhaust gas stream. This is known as ammonia slip. A 10 ppm ammonia slip in the exhaust gases amounts to nearly 30 tons of ammonia being released each year. There are also concerns about secondary emissions resulting from the continuous introduction of ammonia into the stack gases, such as the formation of nitrous oxide and nitrosoamines. In addition to the continuous release of ammonia, the threat of an accidental release of ammonia associated with its transportation, handling and storage must be addressed. When considering that approximately 300 tons of anhydrous ammonia will be needed annually for the life of the project, the potential for an accidental release increases dramatically.

In addition to ammonia emissions, an SCR system will result in higher emissions of sulfur trioxide (SO_3), also an extremely hazardous substance. These higher emissions are associated with the additional oxidization of SO_2 to SO_3 across the catalyst. These SO_3 emissions can be expected to further react with ammonia to form ammonium bisulfate (NH_4HSO_4) and ammonium sulfate ($(NH_4)_2S0_4$). These emissions will be noted as increased particulate matter emissions. SO_3 can also be expected to form sulfuric acid when combined with the water vapor in the exhaust stack gases.

The spent catalyst from the SCR system will need to be replaced and properly disposed of every five years. This places additional burdens on existing landfill capacities.

Water usage, common to both options, represents approximately 12 million gallons of water per year.

Since the use of an SCR system equipped with a high temperature zeolite catalyst and an air injection system has not been operated in a commercial utility application, all the potential environmental impacts cannot be evaluated at this time. Environmental impacts associated with standard SCR systems have been considered to be significant.

4.4.5 NO_x BACT Summary

Table 4-8 summarizes the NO_x BACT findings. Based on this BACT analysis, an SCR system equipped with a zeolite catalyst and an air injection system in combination with wet injection and dry low NO_x controls would be required in order to meet the most stringent (top) emission limitations . Although determined to be potentially technically feasible, use of

TABLE 4-8
DEERHAVEN CT3
SUMMARY OF TOP-DOWN BACT IMPACT ANALYSIS RESULTS FOR NO_X

	Control Alternatives[1]	
	Option #2 15/30/54[2]	**Option #1 3.5/3.5/11.7**
Emissions		
Turbine (TPY)	276.42	58.22
Reductions (TPY)	Base	218.2
Economic Impacts		
Total Annual Costs ($/Yr)	Base	$1,455,957.53
Incremental Cost Effectiveness ($/Ton)	Base	$6,672.58
Energy Impact		
SCR Power Penalty (kW-Hr/Yr)	Base	1,443,000
Environmental Impacts		
Additional Hazardous Air Pollutant Emissions	No	Yes
Additional Solid Waste Generation	No	Yes
Ammonia Storage and Handling Required	No	Yes

[1] Option #1 - Selective cataltytic reduction
Option #2 - Dry low NO_x combustors and water injection

[2] 54 = 42 ppmvd + 12 ppmvd based on .03% FBN

Source: ENSERCH Environmental, 1994

the combination of control strategies would be unreasonable when considering the economic, energy and environmental impacts. For this project, an incremental cost effectiveness of \$6,672.58 per ton of NO_x removed to meet the most stringent emission limitation was determined based on the addition of a SCR system. This cost, when combined with the associated energy and environmental impacts, is higher than costs for the few projects where SCR has been required and was determined to be neither cost effective nor justifiable. Thus, Option #2, dry low NO_x combustors with water injection, was selected as BACT.

4.5 SULFUR DIOXIDE/SULFURIC ACID MIST EMISSIONS

Sulfur dioxide and sulfuric acid mist emissions are directly related to the sulfur content of the fuel fired in the CT. Review of the BACT/LAER Clearinghouse indicates that the most stringent emission limitations established for NGF and FOF CTs have been based on fuel quality (pre-combustion controls). This is consistent with past EPA findings that the use of add-on air pollution control systems for SO_2 and H_2SO_4 emissions from CTs are technically infeasible. The emission levels identified in Table 3-4 are based on a 95.1 percent conversion of the sulfur in the fuels to SO_2, based on the GE data sheets. In addition, emission levels for H_2SO_4 mist were estimated based on a maximum conversion of 6.5 percent of the sulfur in the fuel.

For NGF operation, a sulfur content of 10 grains per 100 standard cubic feet of gas was used for estimating emissions based on the maximum amount potentially present in the fuel. Use of this conservatively high sulfur content was discussed with the FDEP prior to submittal of this application.

As indicated previously, the proposed combustion turbine will use natural gas as the primary fuel, and very low sulfur fuel oil (0.05% sulfur by weight or lower) for backup fuel. For NGF operations, the use of natural gas is considered BACT for SO_2 and H_2SO_4. For FOF operations, the use of very low sulfur content fuel oil is considered BACT and is equivalent to the most stringent emission limitations recently imposed. Therefore, the proposed unit will meet BACT requirements through fuel specification.

GRU currently has approximately 387,000 gallons of 0.25% sulfur distillate fuel oil in inventory ("existing supply"). GRU anticipates that much of this existing fuel supply may be still in inventory when the proposed unit becomes operational in the summer of 1995. Accordingly, GRU is requesting that FDEP allow the initial use of this fuel oil in the proposed combustion turbine until the existing supply is drawn down to a minimum practical level (5,000 - 10,000 gallons). At that time, additional very low sulfur fuel oil would be added to the tank and would become the fuel used by the existing CTs and other existing usages of distillate fuel oil at the Deerhaven Generating Station in addition to the proposed CT.

GRU believes the request is reasonable and prudent for the following reasons:

- The distillate fuel oil storage and handling facilities at the Deerhaven Site are centralized and were recently upgraded to meet stringent environmental standards. The immediate use of very low sulfur fuel oil for the proposed CT would require the permitting and construction of new facilities.

- The continued use of a centralized facility would reduce operating costs and potential environmental risks associated with additional fuel loading, storage and transfer facilities.

- Assuming there will be no additional distillate fuel oil purchases at this site until the existing supply is drawn down, the existing supply will allow only approximately 54 hours of continuous full load operation at ISO conditions. As the unit startup and testing time on fuel oil is estimated at 30-50 hours, it is anticipated that the majority of the existing supply will be consumed during this initial start-up period.

- Subsequent distillate fuel oil purchases for this facility will be limited to 0.05% sulfur by weight or less. This fuel will also be used in the existing units as well as the proposed combustion turbine resulting in a potential for overall reductions in SO_2 emissions at the Deerhaven Site.

4.6 PARTICULATE MATTER (PM_{10}) EMISSIONS

Particulate matter emissions from CTs are related to the combustion air, fuel quality and combustion efficiency. Review of the BACT/LAER Clearinghouse indicates that most CTs meet the BACT requirement through filtering the combustion air, good combustion practices, use of clean burning natural gas and limited fuel oil firing. Currently, post combustion controls (i.e., baghouse) are not being used on CTs. This is due mostly to the very low PM_{10} emissions associated with CT operations.

PM_{10} emissions result from noncombustibles in the fuels, PM_{10} in the ambient air used as combustion air, dissolved solids in the water used for wet injection and incomplete combustion. Since solids can damage the CT, considerable efforts are made to limit their entry and/or formation. Based on this need and review of the BACT/LAER Clearinghouse data, GRU proposes prefiltering of the combustion air, good combustion practices, and use of natural gas as the primary fuel with limited annual fuel oil firing as BACT. Under these conditions, GRU has been given emission estimates of 7/7/15 pounds per hour of PM_{10} (excluding sulfuric acid mist) during NGF, NGFPA and FOF, respectively. These values represent emission levels of 0.008/0.0064/0.015 pounds per million Btu of heat input.

Section V

5.0 AMBIENT AIR QUALITY MONITORING DATA ANALYSIS

5.1 PSD PRECONSTRUCTION MONITORING APPLICABILITY

As indicated in Section 3.4.4, GRU evaluated the need for preconstruction on-site air quality monitoring in accordance with the requirements of Ch.17-212.400(3)(e). A monitoring exemption request was submitted to FDEP on November 24, 1993 and approved by FDEP on February 11, 1994 (FDEP, 1994). That request contained a brief description of the project and discussions of existing climate and air quality based on regional data as well as a preliminary air quality modelling assessment of the impacts of the proposed CT.

The preliminary modelling results demonstrated that the maximum off-site impacts from the proposed CT will be well below the monitoring significance levels for all of the criteria pollutants (Table 3-3). Those results are conservative as they were based on preliminary emission rates which are in some cases greater than the currently proposed emission rates for the proposed CT. The currently proposed emission rates were used for the revised modelling; the results are included in Section 7.0.

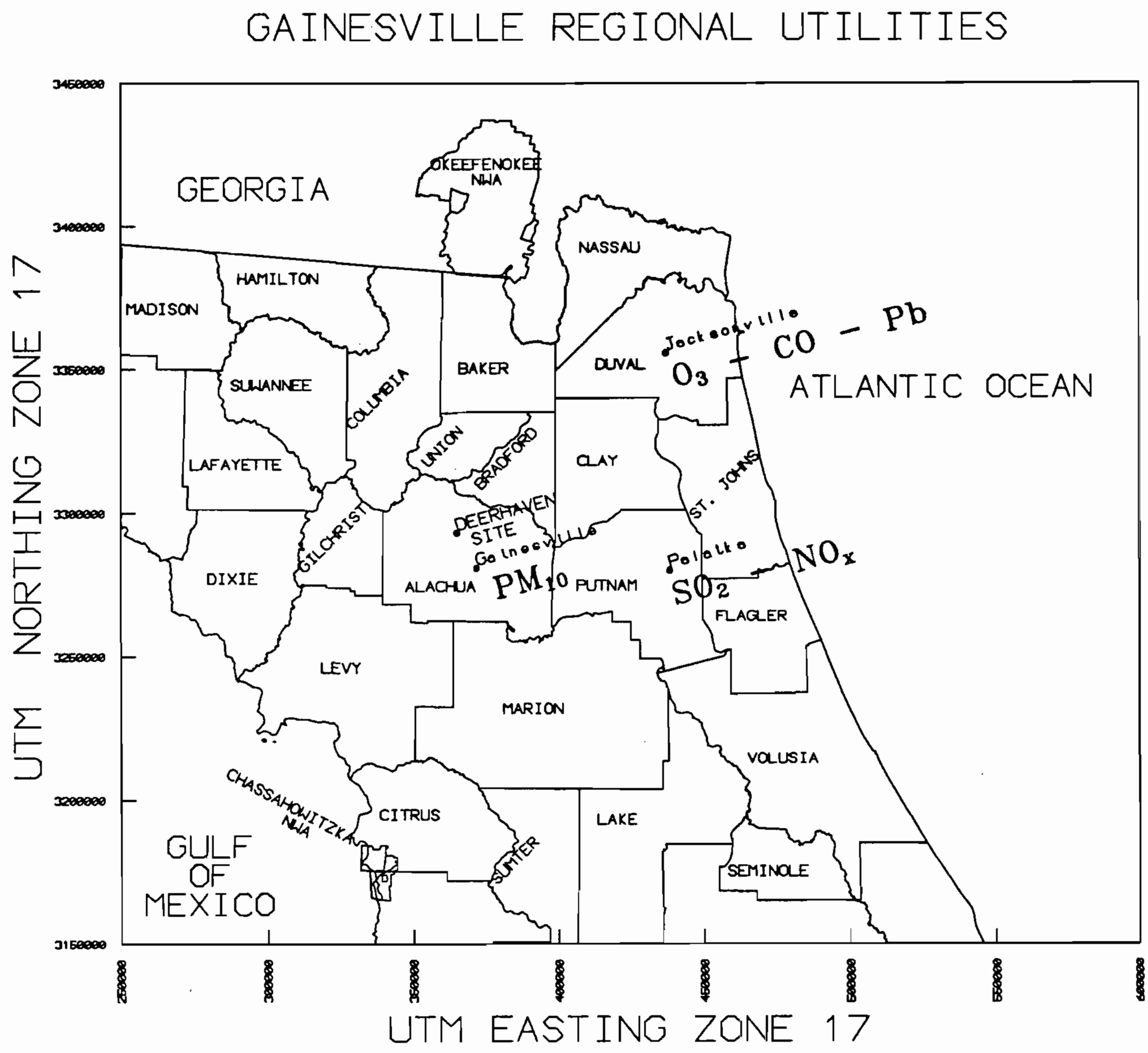
5.2 EXISTING REPRESENTATIVE AIR QUALITY MONITORING DATA

Existing FDEP and GRU ambient air monitoring data are available that can be used to characterize the existing conditions at and in the vicinity of the site. A map depicting the locations of the existing ambient air quality monitoring sites is presented as Figure 5-1. The FDEP and GRU data from these monitors for 1992 are summarized in Table 5-1.

Both FDEP and GRU collected ambient PM_{10} data in the vicinity of the site. The data from both sites indicate that existing PM_{10} concentrations are well below the NAAQS/FAAQS.

Concentrations of SO_2 and NO_2 have been measured by FDEP at Palatka and indicate that existing SO_2 and NO_2 concentrations at that nearby location are well below the NAAQS and FAAQS.

In the site region, ambient data for CO, O_3, and Pb have been collected by FDEP only in the Jacksonville metropolitan area. These pollutants are usually associated with urban environments. Given the rural nature of the project site, concentrations are expected to be significantly lower than those in Jacksonville.



Source: ENSERCH Environmental, 1994

GRU

FDEP Ambient Air Quality Monitoring Stations (1992)

FIGURE

5-1

TABLE 5-1
1992 MONITORING DATA SUMMARIES FOR NEARBY AIR QUALITY MONITORING SITES

Parameter	Station	SAROAD ID	Maximum 1-Hr(1)	Maximum 3-Hr(1)	Maximum 8-Hr(1)	Maximum 24-Hr(1)	Maximum Quarter(1)	Annual(1)
PM_{10}	Gainesville	1420023F02	N/A	N/A	N/A	44	N/A	22
PM_{10}	GRU (9/90-9/91)	N/A	N/A	N/A	N/A	38	N/A	18
SO_2	Palatka	3780008F02	338	216	N/A	23	N/A	9
Ozone	Jacksonville	1960070H01	223	N/A	N/A	N/A	N/A	N/A
NO_x	Palatka (Jan-Mar)	3780005J02	N/A	N/A	N/A	N/A	N/A	13
CO	Jacksonville	1960083H01	13	N/A	6	N/A	N/A	N/A
Lead	Jacksonville	1960084H01	N/A	N/A	N/A	N/A	0.0	N/A

(1) All values are in μg/m^3 except for CO which is in parts per million (ppm).

N/A = Not applicable

Source: GRU, 1991
FDEP, 1993

5.3 CLIMATOLOGY

The climate in northern Florida is classified as subtropical with maritime influences from both the Atlantic Ocean and the Gulf of Mexico. Summers are long, warm and relatively humid, while winters are mild because of the latitude and the warming influence of the Gulf Atlantic.

Climatological data representative of the site are available for the Gainesville Regional Airport, which is located approximately 15 km to the southeast. A summary of temperature and precipitation data for Gainesville, Florida is presented in Table 5-2.

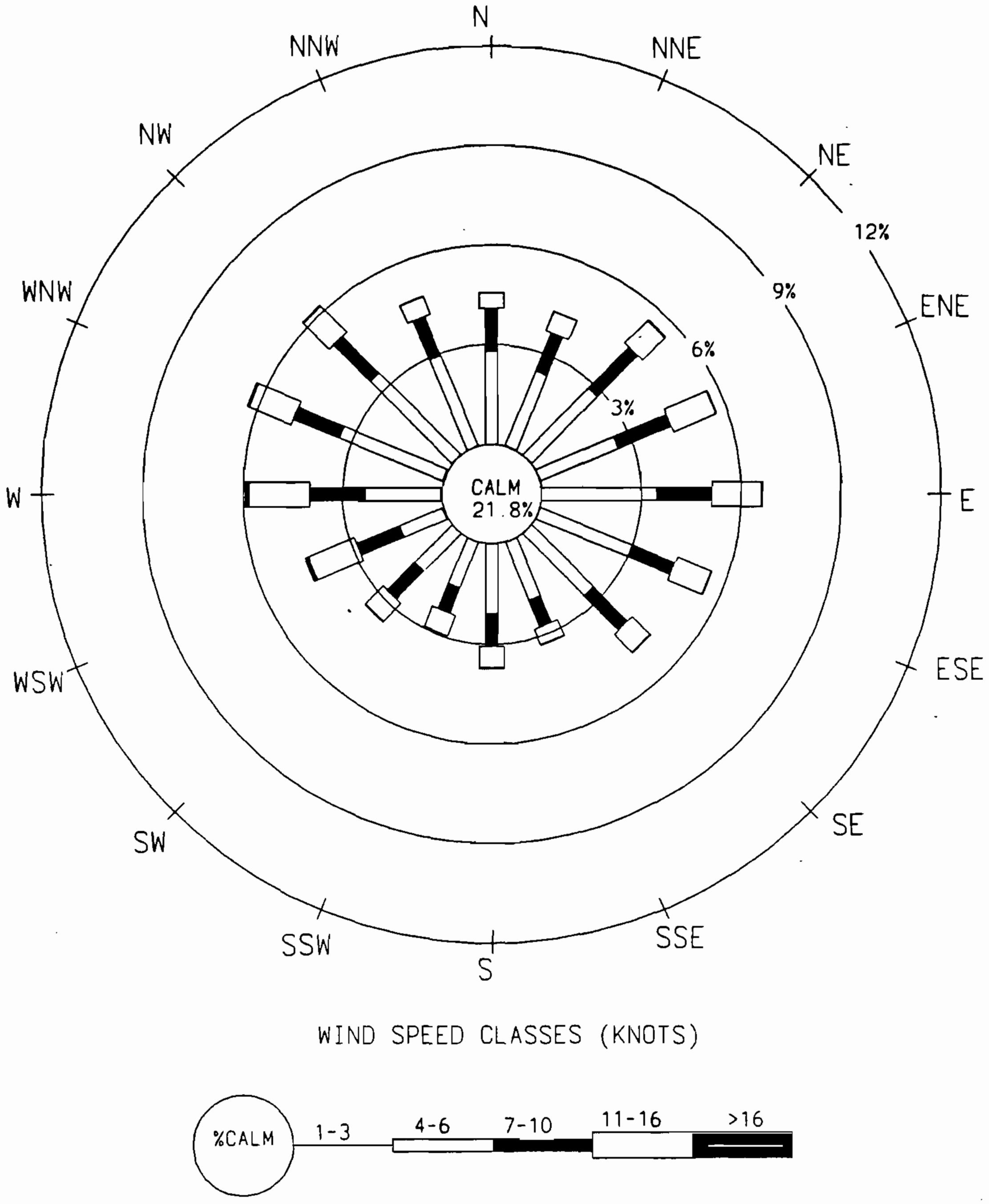
TABLE 5-2

Temperature and Precipitation Summary - Gainesville, Florida

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Ann
Mean Temp (°F)	54.6	56.4	62.4	68.4	74.6	79.0	80.8	80.8	78.5	70.3	61.9	56.0	68.6
Mean Max Temp (°F)	66.7	68.5	75.1	81.1	86.6	89.5	90.5	90.5	87.8	81.1	73.9	68.1	80.0
Mean Min Temp (°F)	42.5	43.7	49.7	55.7	62.5	68.4	71.0	71.1	69.2	59.4	49.8	43.9	57.2
Mean Precip (In)	3.23	3.92	3.53	2.94	4.14	6.34	6.99	8.07	5.50	2.45	2.04	3.24	52.39

Source: NOAA, 1989 (Period of Record 1951-1980)

Five years of wind data selected to represent the Deerhaven Site were obtained from the National Weather Service station at the Gainesville Regional Airport. Based on these data, the annual average wind speed is 6.3 mph. The prevailing wind direction during the 1985-1989 time period was from the east, which occurred approximately seven percent of the time. Wind directions from the west, west-northwest, and northwest each occurred approximately six percent of the time. An annual wind rose for Gainesville for this time period is presented in Figure 5-2, and quarterly wind roses are presented in Figure 5-3.



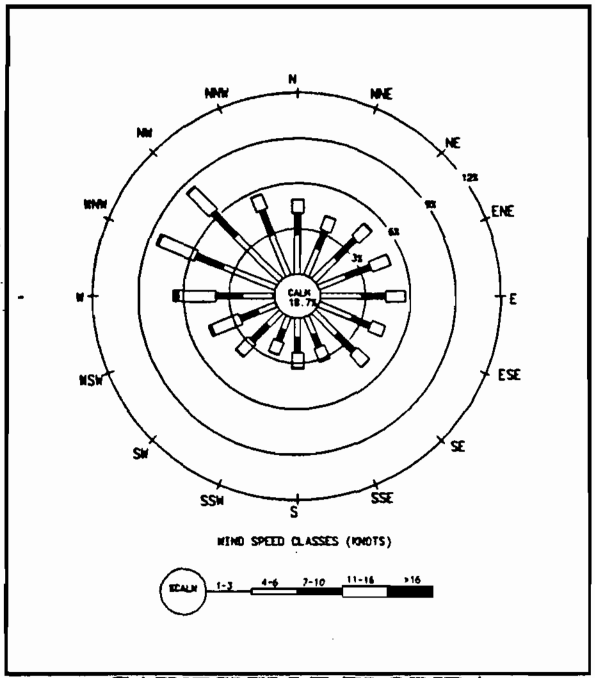
GAINESVILLE FLORIDA
1985 - 1989

Source: ENSERCH Environmental, 1994

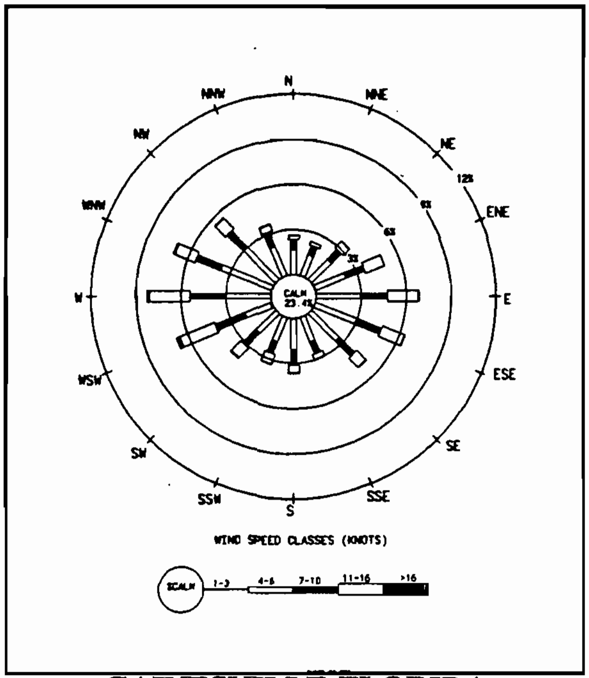
GRU

Annual Wind Rose

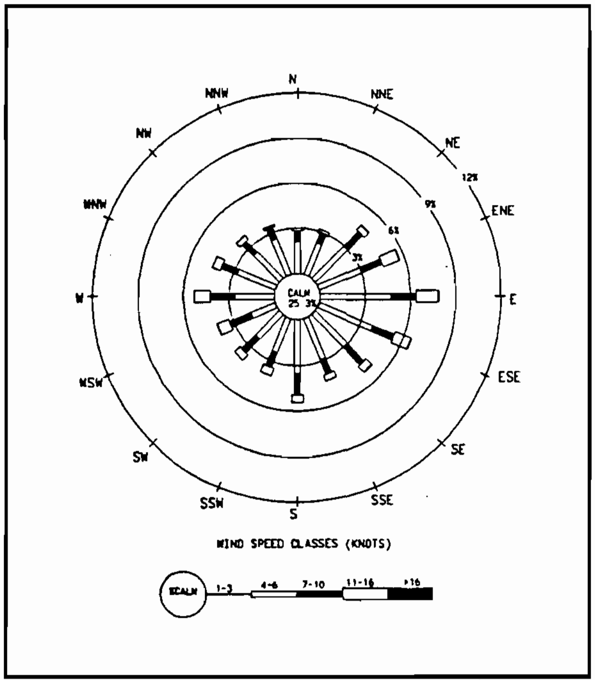
FIGURE
5-2



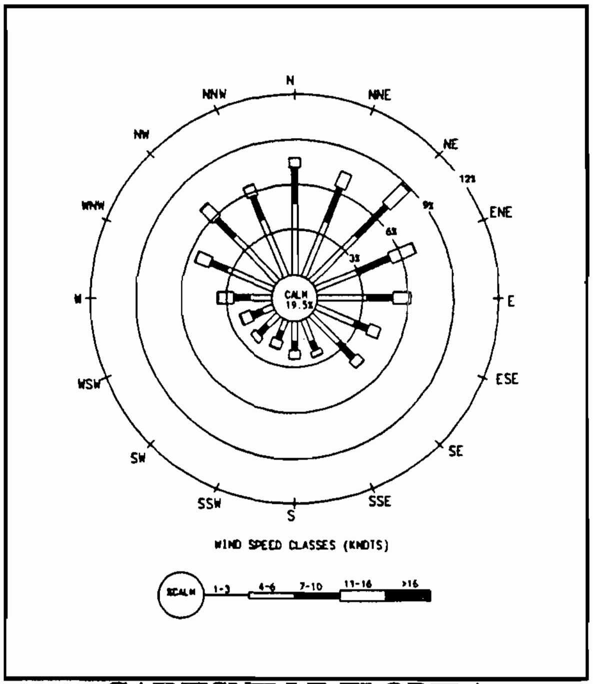
GAINESVILLE FLORIDA
1985 - 1989 JAN - MAR



GAINESVILLE FLORIDA
1985 -1989 APR - JUN



GAINESVILLE FLORIDA
1985 - 1989 JUL - SEP



GAINESVILLE FLORIDA
1985 - 1989 OCT - DEC

Source: ENSERCH Environmental, 1994

GRU	Quarterly Wind Roses	FIGURE 5-3

Section VI

6.0 AIR QUALITY MODELLING APPROACH

This section summarizes the air quality modelling protocol and input parameters utilized in the air impact determinations presented in Section 7.0. Descriptions of the models, meteorology, options selected, listings of modelling parameters for the proposed CT, receptor locations, and step-by-step procedures that were used to develop the necessary projected impacts are discussed.

6.1 POLLUTANTS COVERED

The required modelling analysis is limited to those pollutants that were determined to be subject to PSD review in Section 3.4.3, Table 3-4 (NO_x, SO_2, PM_{10}, and sulfuric acid mist). Although the proposed source emissions of sulfuric acid mist are shown in Table 3-4 to be above the PSD significant emission rates there are no ambient air quality standards nor PSD significant impact levels or increments for this pollutant. Hence, the air quality impact assessment for sulfuric acid mist is limited to prediction of the maximum impacts from the proposed facility. Conventional modelling for compliance with AAQS and PSD increments was therefore restricted to NO_x, SO_2 and PM_{10}. Hazardous air pollutants (HAPs) not subject to PSD review but regulated under the CAA Amendments of 1990 for which emission estimates were available for this project (antimony, arsenic, cadmium, chromium, cobalt, formaldehyde, manganese, nickel and selenium) were also included in the air quality impact analysis.

6.2 GENERAL MODELLING APPROACH

As required by the PSD regulations, the air quality impact assessment consists of a proposed source impact assessment versus the monitoring significance levels, a significant impact area analysis, a PSD increment consumption analysis, an ambient air quality standards impact analysis, and an additional impacts analysis. These analyses are discussed in greater detail in the following paragraphs under specific modelling methodologies. The modelling approach followed EPA and FDEP modelling guidelines for determining compliance with applicable PSD increments and ambient air quality standards. A modelling protocol was prepared by the applicant and submitted to FDEP for review (GRU, 1993a). The FDEP approved the modelling protocol (FDEP, 1993a) prior to commencement of the air quality impact assessment.

6.3 MODEL SELECTION AND OPTIONS

6.3.1 Dispersion Model Selection

The area surrounding the Deerhaven Generating Station has been determined to be a rural area based upon the technique for urban/rural determinations documented in the EPA *Guideline on Air Quality Models (Revised)* (EPA, 1993a) which applies land use criteria. Based upon this determination, the refined ISCST2 dispersion model (Version 93109) was selected for use in the air quality impact analysis used to support the PSD permit application. The ISCST2 model, documented in a user's guide (EPA, 1992), is a referenced EPA dispersion model recommended for use in rural areas, and for application to point, area, and volume sources. The ISCST2 model can predict the maximum (highest) as well as the highest, second-highest concentrations and periods of occurrence for 1-hour, 3-hour, 8-hour, 24-hour, and annual averaging periods at each receptor for each full year of hourly meteorological data used.

6.3.2 Dispersion Model Options

The regulatory default mode for all of the program control parameters was used in the ISCST2 model as approved by FDEP. The ISCST2 model was applied without terrain adjustment data because the area in which the Deerhaven Generating Station is located has very little relief (e.g., a net change in ground level elevation in the range of only 10-20 feet). The ISCST2 model's building downwash options were applied because the stack for the proposed source will be less than GEP stack height.

Because proposed emissions would come from a single stack, emissions impacts for the proposed source with respect to all applicable pollutants were scaled with reference to emissions of one gram per second. The air quality impact assessment for PM assumed that all PM emissions were PM_{10} emissions. This assumption simplified the PM modelling analysis and resulted in a conservative approach to modelling PM_{10} impacts.

6.4 METEOROLOGICAL DATA

The air quality modelling analysis used hourly preprocessed National Weather Service (NWS) surface meteorological data from Gainesville Regional Airport, Florida, and concurrent twice-daily upper air soundings from Tampa (Ruskin), Florida, for the years 1985-1989. The meteorological data were supplied by FDEP in the preprocessed format required by the ISCST2 model. The preprocessed hourly meteorological data file for each year of record used in the analysis contains randomized wind direction, wind speed, ambient temperature, atmospheric stability using the Turner (1970) stability classification scheme, and mixing heights. The anemometer height of 6.7 meters, used in the modelling analysis, was obtained from NWS Local Climatological Data summaries for Gainesville, Florida (NOAA, 1989).

6.5 EMISSIONS INVENTORY

The emissions inventories for the proposed source and fuel scenarios are presented in Tables 6-1 and 6-2. The pollutant emission rates shown in these tables are representative of BACT as demonstrated in Section 4.0.

The proposed source worst-case fuel/load/temperature scenarios were determined by first conducting preliminary modelling. Preliminary modelling runs were conducted using one year of meteorology (1988) at three ambient temperatures (95°F, 75°F, and 20°F) and three CT loads (100%, 80%, and 60%) for both natural gas and distillate fuel oil. In addition, a modelling run was conducted for the CT power augmentation mode at 95°F and 100% load. Thus, there were a total of 19 preliminary modelling runs conducted using the 1988 meteorological data set. A summary of the preliminary modelling runs is presented in Section 7.1.

As a result of these preliminary runs, it was determined that there were four different temperature and load combinations which caused the "worst case" ground-level ambient air quality impacts for the different averaging periods and pollutants. The "worst-case" emission rates, stack parameters and temperature/load information for the averaging times and pollutants are listed in Table 6-3.

The emission rates for hazardous air pollutants were based on distillate fuel oil firing at 100 percent load and 20°F. The emission factors used and the calculated emission rates are contained in Table 6-4.

TABLE 6-1
PROPOSED SOURCE EMISSIONS INVENTORY
NATURAL GAS FIRING

Load (%)	Ambient Temperature (°F)	Hs (m)	Ts (°K)	Vs (m/sec)	Ds (m)	Emission Rates (g/sec)		
						SO_2[1]	PM	NO_x
100	20	15.8	791	48.7	4.3	3.67	0.88	7.31
	59	15.8	805	45.5	4.3	3.32	0.88	6.68
	75	15.8	811	44.0	4.3	3.18	0.88	6.43
	95	15.8	817	42.1	4.3	2.96	0.88	5.93
80	20	15.8	804	40.5	4.3	3.06	0.88	6.18
	59	15.8	823	38.5	4.3	2.80	0.88	5.55
	75	15.8	831	37.5	4.3	2.71	0.88	5.42
	95	15.8	843	36.5	4.3	2.59	0.88	5.17
60	20	15.8	831	35.2	4.3	2.60	0.88	5.17
	59	15.8	851	35.9	4.3	2.40	0.88	4.79
	75	15.8	859	32.8	4.3	2.32	0.88	4.67
	95	15.8	866	32.0	4.3	2.22	0.88	4.41
100+[2]	59	15.8	805	46.6	4.3	3.74	0.88	5.30
	95	15.8	819	43.3	4.3	3.37	0.88	4.79

(1) Based on 10 grains/100 SCF total sulfur in natural gas.
(2) 100+ - Power augmentation mode

CT UTM Coordinates: 365.54 km - East
3,292.72 km - North

Source: ENSERCH Environmental, 1994

Hs - Stack height
Ts - Stack exit temperature
Vs - Stack exit velocity
Ds - Stack diameter

TABLE 6-2
PROPOSED SOURCE EMISSIONS INVENTORY
FUEL OIL FIRING

Load (%)	Ambient Temperature (°F)	Hs (m)	Ts (°K)	Vs (m/sec)	Ds (m)	Emission Rates (g/sec)		
						SO_2[1]	PM	NO_x
100	20	15.8	786	49.5	4.3	33.54	1.89	29.89
	59	15.8	800	46.2	4.3	30.21	1.89	26.86
	75	15.8	807	44.5	4.3	28.62	1.89	25.35
	95	15.8	815	42.8	4.3	26.95	1.89	23.84
80	20	15.8	811	40.3	4.3	28.24	1.89	24.84
	59	15.8	834	38.8	4.3	25.62	1.89	24.34
	75	15.8	839	37.7	4.3	24.34	1.89	21.44
	95	15.8	843	36.6	4.3	23.05	1.89	20.30
60	20	15.8	849	35.7	4.3	23.88	1.89	20.93
	59	15.8	855	33.9	4.3	21.77	1.89	19.04
	75	15.8	859	33.1	4.3	20.74	1.89	18.16
	95	15.8	862	32.2	4.3	19.70	1.89	17.28

[1] Based on 0.25% sulfur in fuel oil. Future use will be based on 0.05% sulfur in fuel oil.

CT UTM Coordinates:	
	365.54 km - East
	3,292.72 km - North

Hs - Stack height
Ts - Stack exit temperature
Vs - Stack exit velocity
Ds - Stack diameter

Source: ENSERCH Environmental, 1994

TABLE 6-3
EMISSION INFORMATION FOR WORST-CASE AMBIENT IMPACT SCENARIOS

Pollutant	Averaging Period	Worst Case Fuel	Temperature (°F)	CT Load (%)	Stack Parameters				Emission Rate (g/s)
					Ts (°K)	Vs (m/s)	Hs (m)	Ds (m)	
SO_2	Annual	Gas/Fuel Oil[1]	20	80	811.33	46.02	15.8	4.3	7.25
	24-hour	Fuel Oil[2]	20	80	811.33	46.02	15.8	4.3	28.24
	3-hour	Fuel Oil[2]	75	60	858.6	33.53	15.8	4.3	20.74
PM_{10}	Annual	Gas/Fuel Oil	95	60	861.89	32	15.8	4.3	0.62
	24-hour	Fuel Oil	95	60	861.89	32	15.8	4.3	1.89
CO	8-hour	Fuel Oil	20	60	848.56	38.71	15.8	4.3	7.95
	1-hour	Fuel Oil	75	60	848.56	38.71	15.8	4.3	7.31
NO_x	Annual	Gas/Fuel Oil	20	80	811.33	46.02	15.8	4.3	7.61

[1] Based on 0.25% sulfur fuel oil, and natural gas containing 10 grains/100 SCF total sulfur - 2000 hr/yr FOF, 1510 hr/yr NGF, and 390 hr/yr PA.

[2] Based on 0.25% sulfur fuel oil. Future oil use will be on 0.05%S basis and emissions will be lower.

[3] CO was included in the preliminary modelling runs for the monitoring exemption request and significant impact area analyses. It was later determined that CO emissions were below the PSD significant emission rate and need not be included in the modelling.

Ts - Stack temperature
Vs - Exit velocity
Hs - Stack height
Ds - Stack diameter

Source: ENSERCH Environmental, 1994

TABLE 6-4
HAZARDOUS AIR POLLUTANT EMISSION INVENTORY

Pollutant	Emission Factor[1] (Lbs/mmBTU)	Emission Rates	
		(Lbs/Hr)	(g/s)
Antimony	2.20e-05	2.42e-02	3.05e-03
Arsenic	4.90e-06	5.39e-03	6.80e-04
Beryllium	3.30e-07	3.63e-04	4.58e-05
Cadmium	4.20e-06	4.62e-03	5.83e-04
Chromium	4.70e-05	5.17e-02	6.52e-03
Cobalt	9.10e-06	1.00e-02	1.26e-03
Formaldehyde	(1)	4.50e+00	5.78e-1
Lead	5.80e-05	6.38e-02	8.05e-03
Manganese	3.40e-04	3.74e-01	4.72e-02
Mercury	9.10e-07	1.00e-03	1.26e-04
Nickel	1.20e-03	1.32e+00	1.66e-01
Selenium	5.30e-06	5.83e-03	7.35e-04

[1] Emission factors are from AP-42, Section 3.1, Table 3.1-7, with the exception of formaldehyde which is based on the VOC emission rate of 4.5 lbs/hr. This assumes all VOC emitted during NGFPA is formaldehyde.

Source: ENSERCH Environmental, 1994

6.6 RECEPTOR LOCATIONS

6.6.1 Receptor Grids for Site Vicinity

Ambient concentrations were determined for the significant impact area and monitoring exemption analyses for receptors in a polar grid consisting of 36 radial directions at 10 degree intervals at distances listed below (in kilometers) from the site origin, the new CT:

1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
5.5
6.0
7.0
8.0
9.0
10.0
11.0
12.0
13.0
14.0
15.0
16.0
17.0
18.0
19.0
20.0

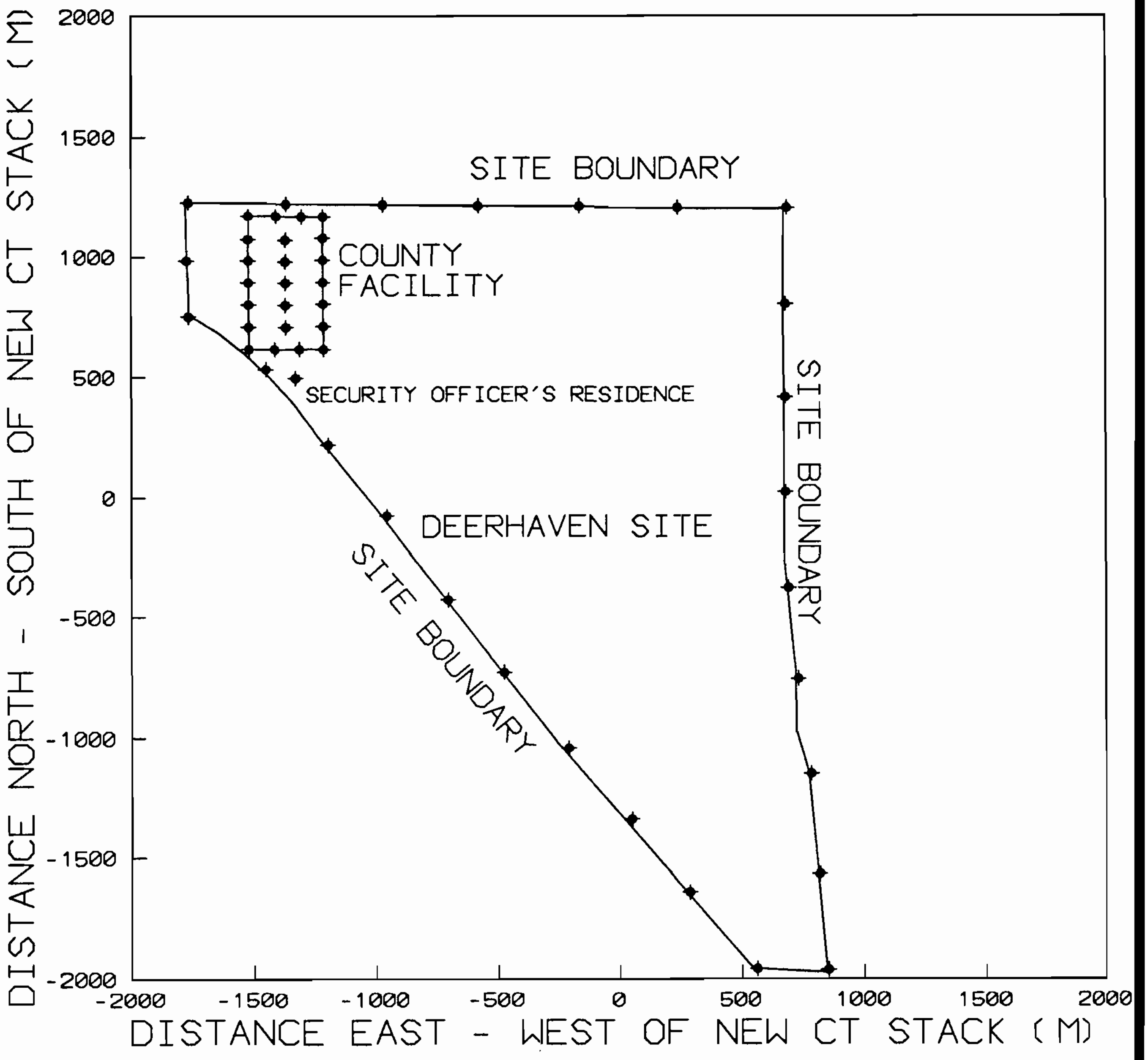
Receptors from these polar grids which fell within the project site boundaries were not included but 26 additional receptors were placed around the site boundary. In addition, receptors were placed around the perimeter of the Alachua County Public Works facility located within the project site boundary and at a security officer's residence which is also located within the site boundary. Figure 6-1 presents the location of the site boundary receptors.

As requested by FDEP, additional receptor rings were added at 250 m intervals, 1 km either side of the receptor ring which contained the highest predicted impact from the preliminary modelling runs which identified the worst case temperature/load combinations. Figures 6-2 through 6-7 depict the locations of these receptors along with the original receptors for various pollutant, averaging time, ambient temperature and CT load combinations.

These more refined receptor grids were used and all five years of meteorological data were run for the "worst case" load and ambient temperature combinations previously described.

6.6.2 Receptor Grid for Class I PSD Analysis

The modelling for the Chassahowitzka National Wilderness Area analysis used a 13-point receptor grid obtained from FDEP. This grid consists of a series of points located along the boundary of the Class I area. The coordinates of these points are listed in Table 6-5. The modelling for the Okefenokee PSD Class I Area analysis used a 10-point receptor grid also

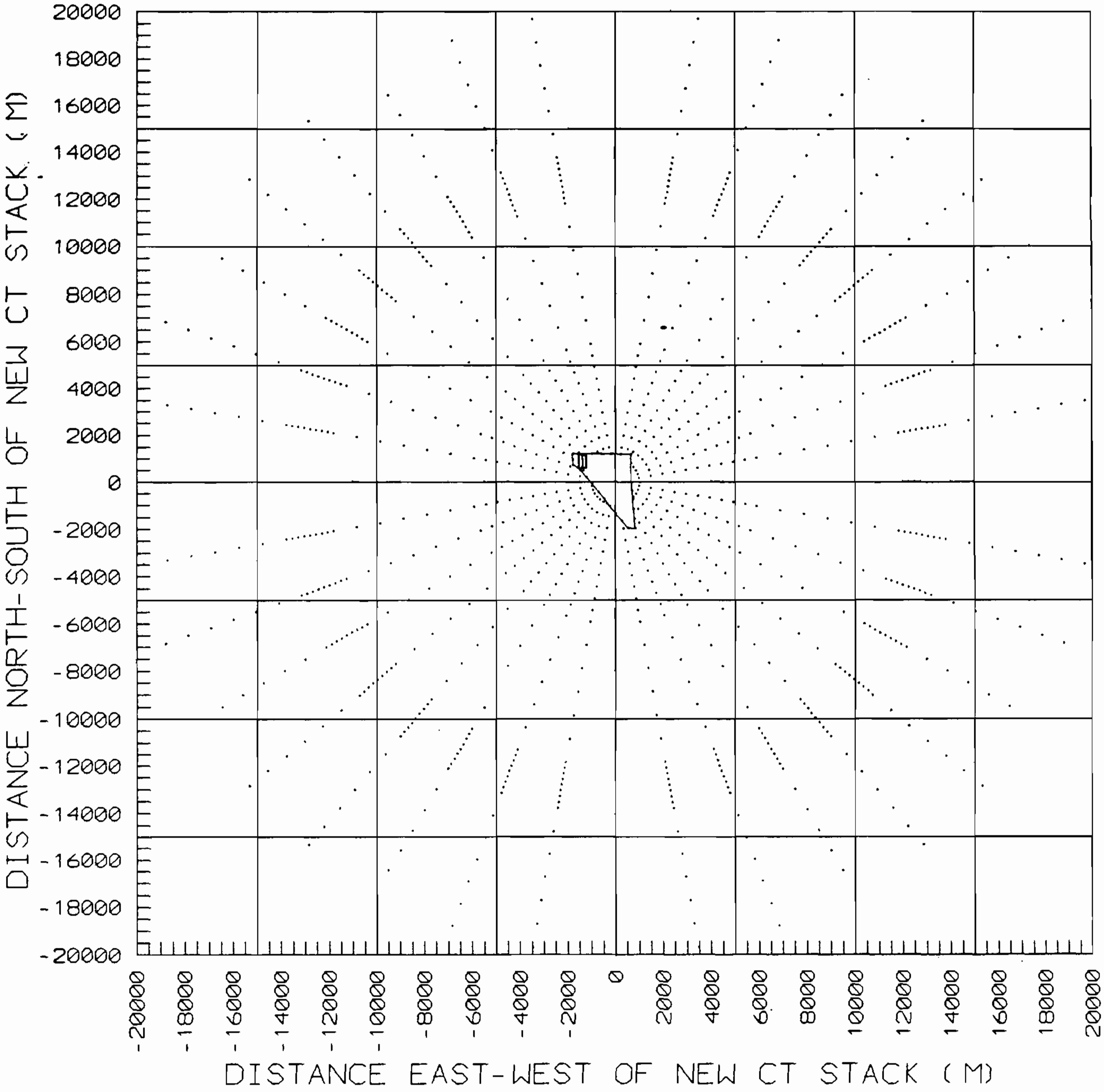


Source: ENSERCH Environmental, 1994

GRU

ISCST2 RECEPTOR LOCATIONS
Site Boundary, County Facility
and Security Officer's Residence

FIGURE
6-1

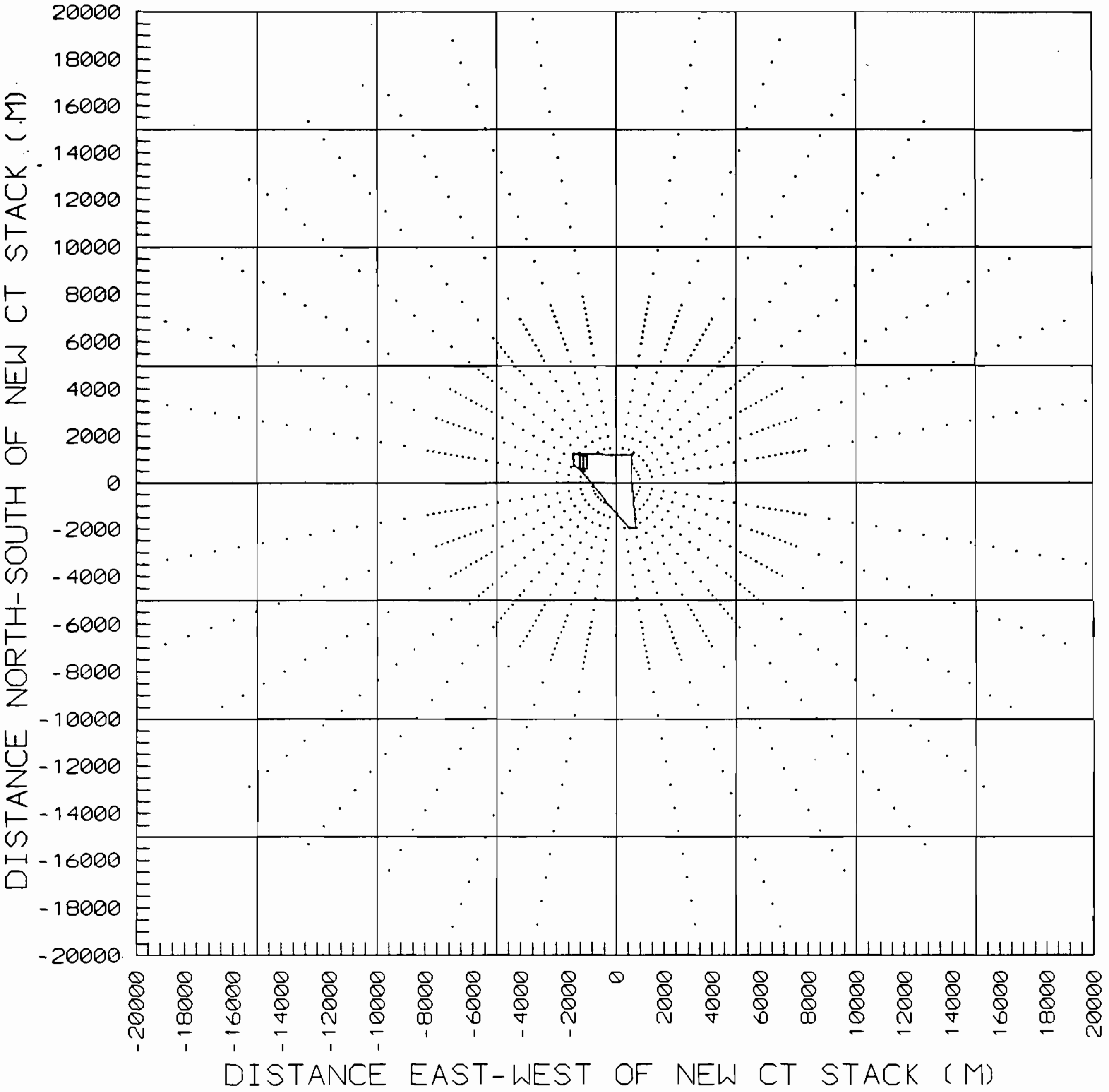


Source: ENSERCH Environmental, 1994

GRU

ISCST2 RECEPTOR LOCATIONS
SO_2 24-Hour - 20°F 80% Load

FIGURE
6-2

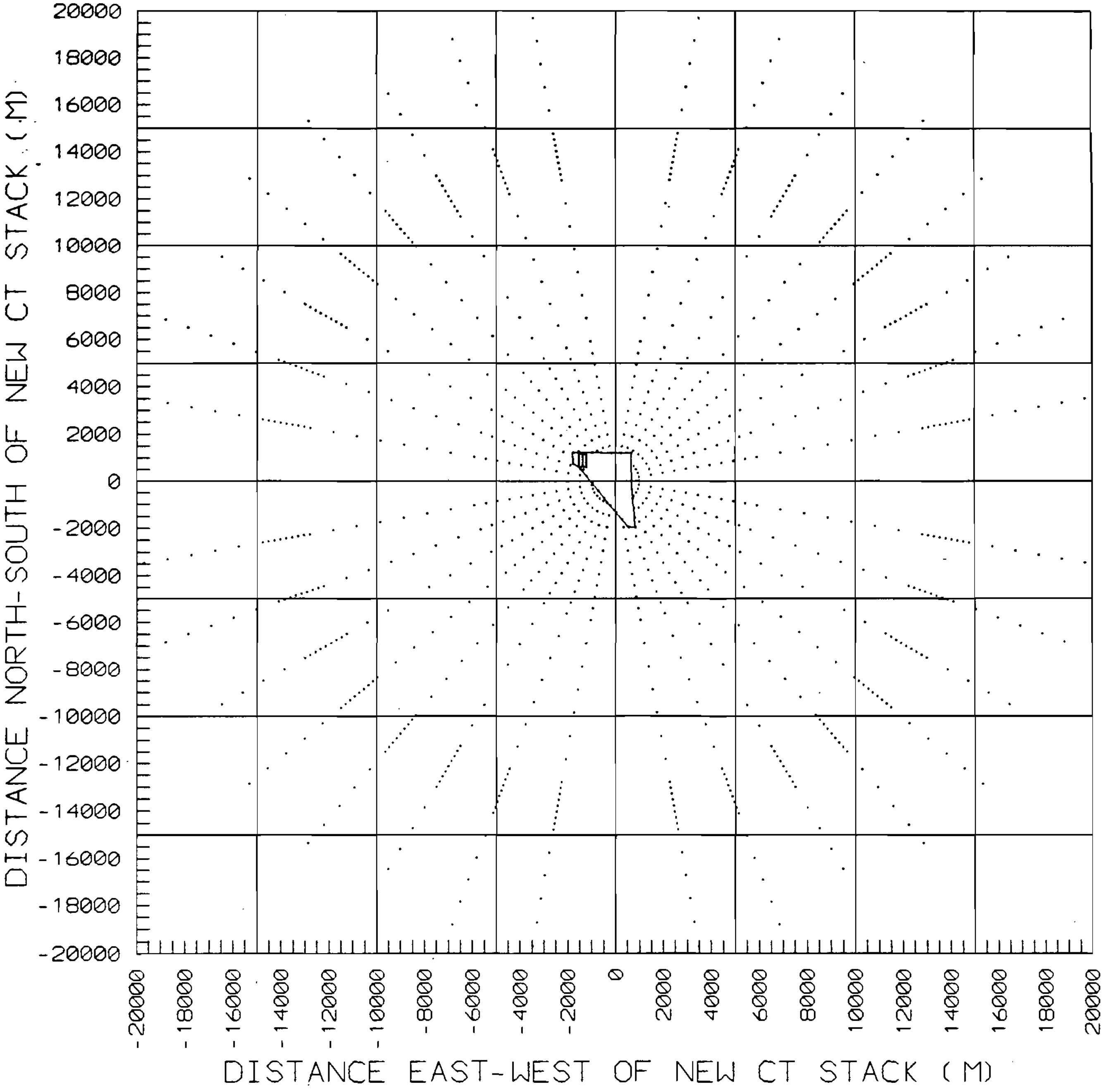


Source: ENSERCH Environmental, 1994

GRU

ISCST2 RECEPTOR LOCATIONS
SO_2 and NO_X Annual - 20°F 80% Load

FIGURE
6-3

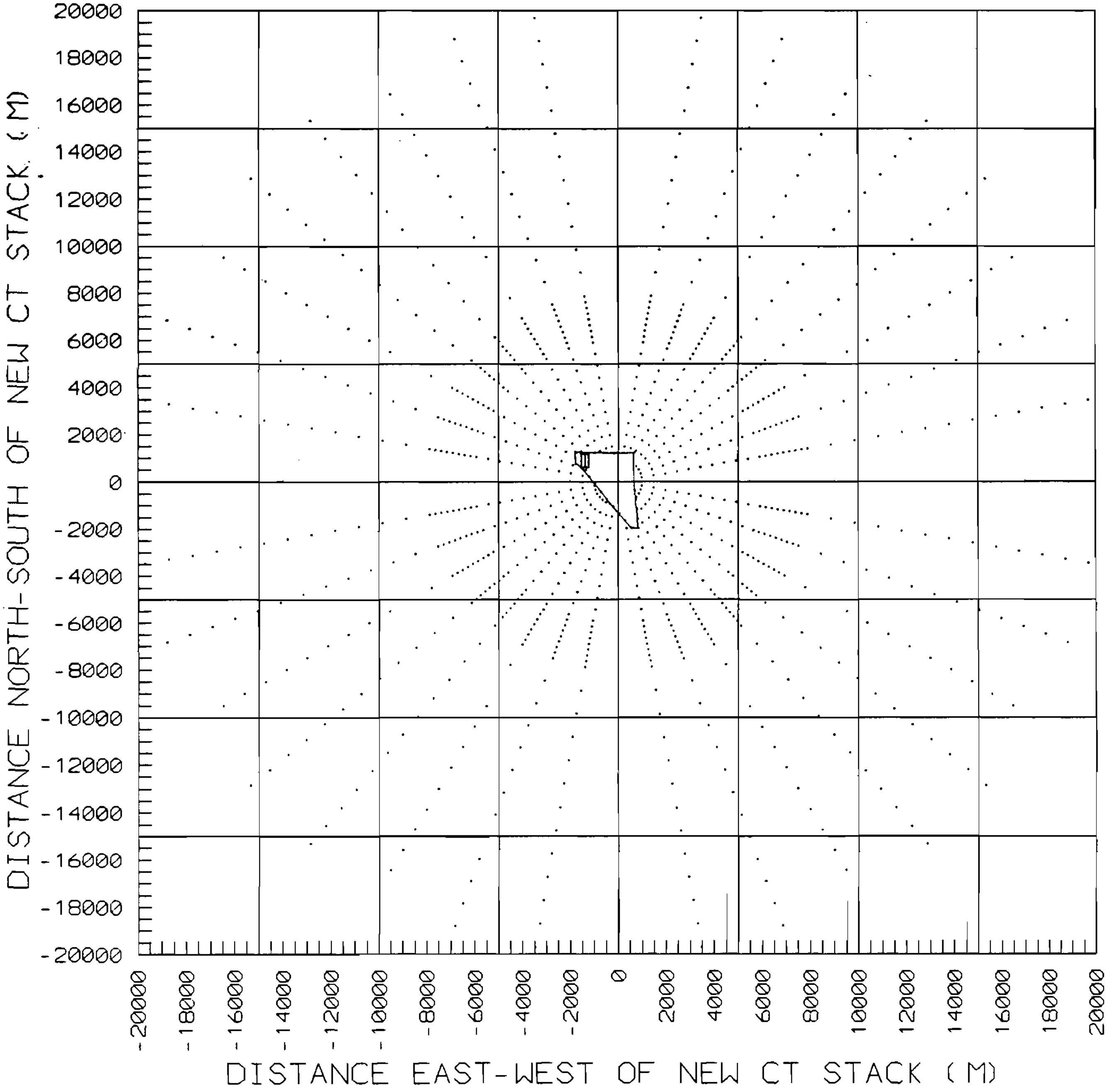


Source: ENSERCH Environmental, 1994

GRU

ISCST2 RECEPTOR LOCATIONS
PM_{10} 24-Hour - 95°F 60% Load

FIGURE
6-4

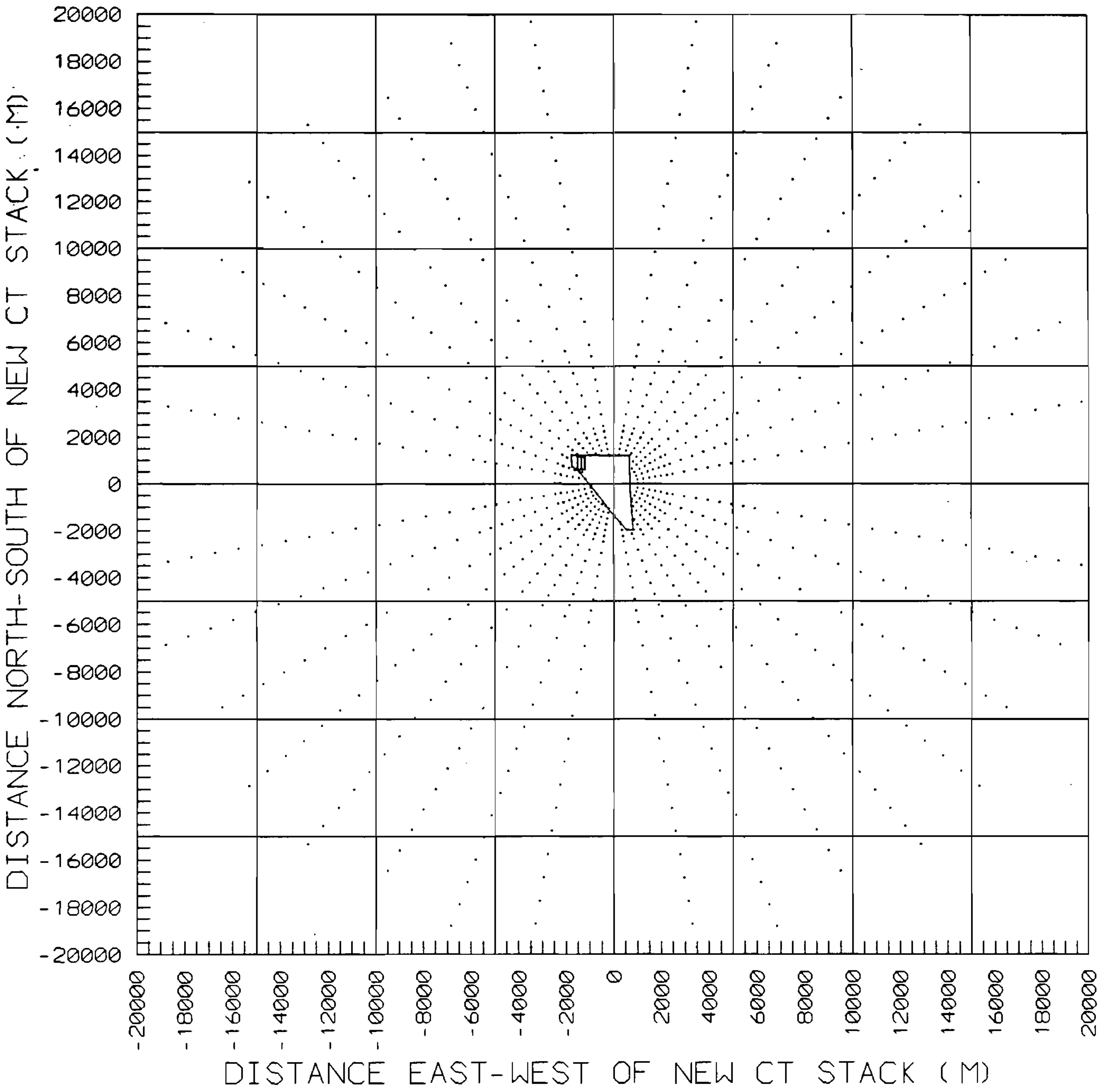


Source: ENSERCH Environmental, 1994

GRU

ISCST2 RECEPTOR LOCATIONS
PM_{10} Annual - 95°F 60% Load

FIGURE
6-5

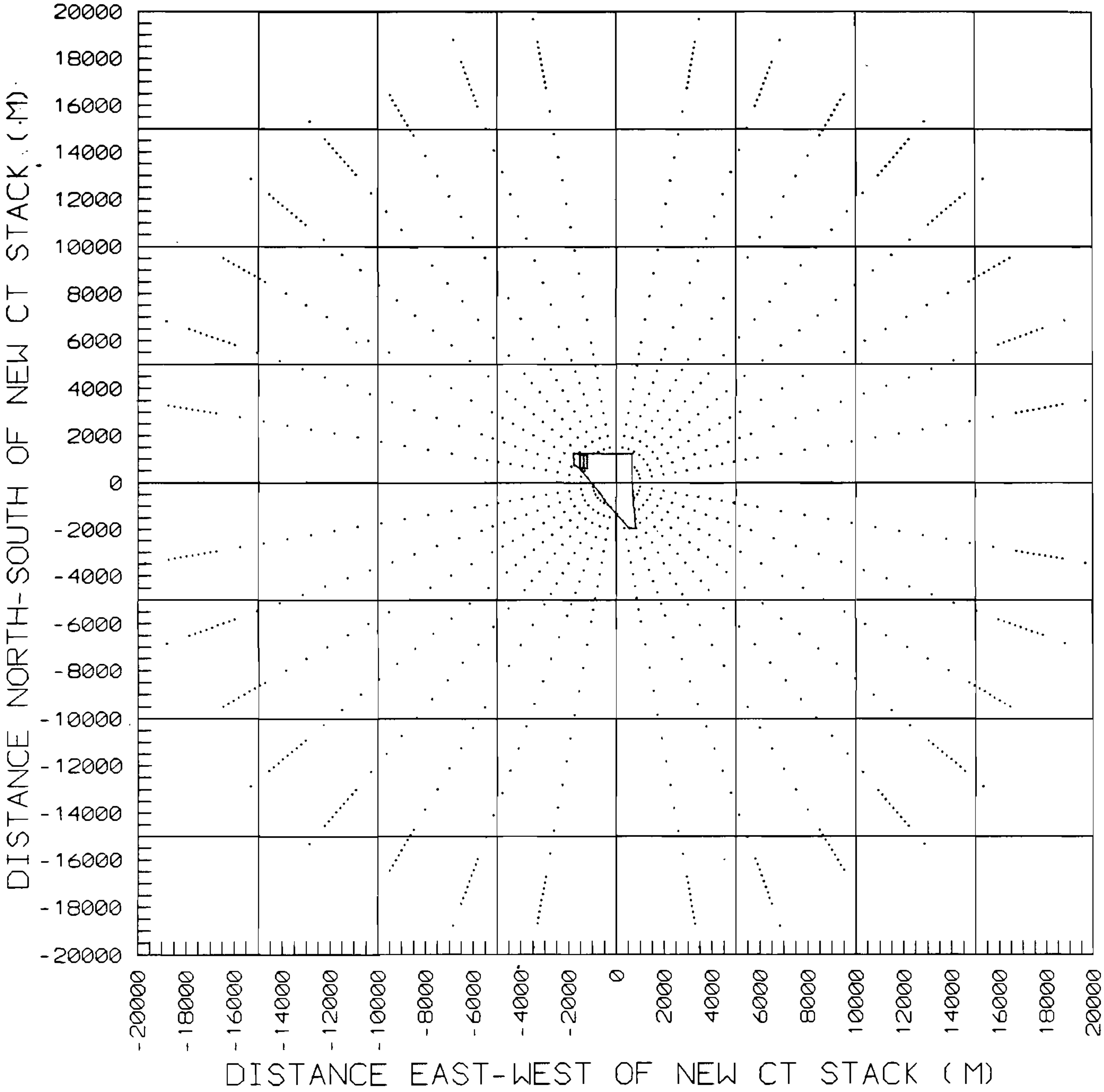


Source: ENSERCH Environmental, 1994

GRU

ISCST2 RECEPTOR LOCATIONS
SO_2 3-Hour and CO 1 Hour - 75°F 60% Load

FIGURE
6-6



Source: ENSERCH Environmental, 1994

GRU

ISCST2 RECEPTOR LOCATIONS
CO 8 - Hour - 20°F 60% Load

FIGURE
6-7

TABLE 6-5
RECEPTOR GRID FOR CHASSAHOWITZKA PSD CLASS I AREA

	UTM Coordinates		Distance from Deerhaven Generating Station[1]		
Point	**East (km)**	**North (km)**	**ΔX (km)**	**ΔY (km)**	**Distance (km)**
1	340.3	3,165.7	25.24	127.02	129.5
2	340.3	3,167.7	25.24	125.02	127.5
3	340.3	3,169.8	25.24	122.92	125.5
4	340.7	3,171.9	24.84	120.82	123.3
5	342.0	3,174.0	23.54	118.72	121.0
6	343.0	3,176.2	22.54	116.52	118.7
7	343.7	3,178.3	21.84	114.42	116.5
8	342.4	3,180.6	23.14	112.12	114.5
9	341.1	3,183.4	24.44	109.32	112.0
10	339.0	3,183.4	26.54	109.32	112.5
11	336.5	3,183.4	29.04	109.32	113.1
12	334.0	3,183.4	31.54	109.32	113.8
13	331.5	3,183.4	34.04	109.32	114.5

(1) Location of "zero point" for Deerhaven Generating Station is 365.540 km east, 3,292.720 km north.

Note: The general location of the PSD Class I Chassahowitzka Wilderness Area is depicted in Figure 1-1.

obtained from FDEP consisting of points along the southern and eastern boundary of the Okefenokee. The coordinates of these points are listed in Table 6-6.

6.7 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with structures planned for and existing at the Deerhaven Generating Station, the 15.8 meter stack for the proposed CT unit will be less than the calculated GEP stack height (38 meters). Therefore, the potential for building downwash to occur was considered in the modelling analysis.

The procedures used for addressing the effects of building downwash are those recommended in the *User's Guide For the Industrial Source Complex (ISC2) Dispersion Models* (EPA, 1992). The building height and effective width are input to the model, which uses these parameters to calculate downwash. For short stacks (i.e., physical stack height is less than $H_b + 0.5 L_b$, where H_b is the building height and L_b is the lesser of the building height or projected width), the Schulman and Scire (1980) method is used. For cases where the physical stack is greater than $H_b + 0.5 L_b$ but less than GEP, the Huber-Snyder (1976) method is used. Direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10-degree sector.

In the case of the proposed CT unit, the turbine structure is the dominant building of influence. Utilizing the input stack height and direction specific building dimensions, the ISC2 model selects the appropriate method to calculate building downwash based on the $H_b + 0.5 L_b$ criteria.

Cavity calculations were not performed since all of the nearby structures are well over three times the height of the nearby structures from the site boundary, and no off-site influences are expected.

TABLE 6-6
RECEPTOR GRID FOR OKEFENOKEE PSD CLASS I AREA

Point	UTM Coordinates		Distance from Deerhaven Generating Station[1]		
	East (km)	North (km)	ΔX (km)	ΔY (km)	Distance (km)
1	391.0	3,471.0	25.46	124.28	126.9
2	390.0	3,410.0	24.46	117.28	119.8
3	392.0	3,400.0	26.46	107.28	110.5
4	390.0	3,395.0	24.46	102.28	105.2
5	391.0	3,390.0	25.46	97.28	100.6
6	390.0	3,384.0	24.46	91.28	94.5
7	383.0	3,384.0	17.46	91.28	92.9
8	378.0	3,382.0	12.46	89.28	90.1
9	374.0	3,383.0	8.46	90.28	90.7
10	370.0	3,383.0	4.46	90.28	90.4

(1) Location of "zero point" for Deerhaven Generating Station is 365.540 km east, 3,292.720 km north.

Note: The general location of the PSD Class I Okefenokee Area is depicted in Figure 1-1.

Section VII

7.0 AIR QUALITY IMPACT ANALYSIS RESULTS

This section summarizes the results of the modelling analyses conducted as described in Section 6.0. It is organized into sections dealing with the worst-case operation, modelled impacts versus monitoring significance levels, significant impact areas, impacts of the project by itself, Class I area impacts, and predicted concentrations of hazardous air pollutants (HAPS) versus FDEP's draft "no threat" levels (FDEP, 1992a).

7.1 WORST-CASE OPERATION ANALYSIS

As indicated in Section 6.5, the proposed CT facility was evaluated for both the primary fuel, natural gas, and the back-up fuel, distillate fuel oil, to determine the worst-case, ground-level ambient air quality impacts. Since the emissions on distillate fuel oil are higher for the criteria pollutants than for natural gas, the analysis of short-term impacts focused on the fuel oil case, at the ambient temperatures and loads which provided the highest modelled impacts for each pollutant and averaging period. The specific loads and ambient temperatures which produce the worst-case impacts are highlighted in Table 7-1, which provides the results of the preliminary modelling analyses for applicable short-term and annual averages for SO_2, NO_2, CO and PM_{10}.

7.2 IMPACTS VERSUS MONITORING SIGNIFICANCE LEVELS FOR APPLICABLE SHORT-TERM AND ANNUAL AVERAGES FOR SO_2, NO_x, CO AND PM_{10}

Each of the worst-case scenarios were modelled using five years of meteorological data. The results of modelling the worst-case operating scenarios were compared to the EPA monitoring significance values. The comparison indicated that none of the criteria pollutants exceeded the monitoring significance values. A monitoring exemption request (GRU, 1993) was submitted to FDEP and approved (FDEP, 1994) based on the five year analysis using preliminary emissions data and receptor grids. The preliminary analysis has been revised based on the final emission rates and the slightly revised receptor grids presented in Sections 6.5 and 6.6.1, respectively, and the results are summarized in Table 7-2.

TABLE 7-1
PRELIMINARY MODELLING RESULTS USING 1988 METEOROLOGICAL DATA

Fuel	CT Load (%)	Temp (°F)	Maximum NO_x ($\mu g/m^3$) Annual	Maximum SO_2 ($\mu g/m^3$)(1)			Maximum CO(2) ($\mu g/m^3$)		Maximum PM_{10} ($\mu g/m^3$)	
				3-Hour	24-Hour	Annual(3)	1-Hour	8-Hour	24-Hour	Annual(2)
Natural Gas	100	95	0.015	0.000	0.000	0.000	1.425	0.294	0.0355	0.0023
Natural Gas	100	75	0.015	0.000	0.000	0.000	1.402	0.306	0.0342	0.0022
Natural Gas	100	20	0.015	0.000	0.000	0.000	1.564	0.334	0.0313	0.0019
Natural Gas	80	95	0.015	0.000	0.000	0.000	1.173	0.262	0.0430	0.0026
Natural Gas	80	75	0.016	0.000	0.000	0.000	1.287	0.281	0.0424	0.0026
Natural Gas	80	20	0.016	0.000	0.000	0.000	1.433	0.300	0.0373	0.0024
Natural Gas	60	95	0.015	0.000	0.000	0.000	1.958	0.437	0.0460	0.0030
Natural Gas	60	75	0.016	0.000	0.000	0.000	1.155	0.253	0.0471	0.0030
Natural Gas	60	20	0.018	0.000	0.000	0.000	1.341	0.309	0.0477	0.0031
Power Aug.	100	95	0.033	0.000	0.000	0.000	1.728	0.378	0.0346	0.0022
Fuel Oil	100	95	0.109	7.175	1.927	0.122	2.799	0.585	0.0738	0.0047
Fuel Oil	100	75	0.112	7.549	1.985	0.125	2.802	0.611	0.0718	0.0045
Fuel Oil	100	20	0.114	8.718	2.121	0.128	2.924	0.679	0.0652	0.0039
Fuel Oil	80	95	0.110	7.091	2.020	0.124	2.384	0.531	0.0905	0.0056
Fuel Oil	80	75	0.113	6.636	2.083	0.127	2.454	0.532	0.0887	0.0054
Fuel Oil	**80**	**20**	**0.122**	7.616	**2.150**	**0.138**	2.750	0.576	0.0789	0.0051
Fuel Oil	**60**	**95**	0.107	8.931	1.882	0.122	3.159	0.702	**0.0985**	**0.0064**
Fuel Oil	**60**	**75**	0.109	**9.307**	1.968	0.124	**3.238**	0.701	0.0984	0.0062
Fuel Oil	**60**	**20**	0.116	7.385	2.134	0.132	3.095	**0.705**	0.0924	0.0057

(1) Preliminary runs based on 0.46%S in fuel oil and negligible amounts in natural gas.

(2) Preliminary runs included CO. It was later determined that CO would not be emitted in PSD significant quantities.

(3) Preliminary runs based on 8,760 hours/year operation.

Note: Worst-case, ground-level ambient impact scenarios are highlighted.

Source: ENSERCH Environmental, 1994

TABLE 7-2
MODELLING RESULTS FOR MONITORING EXEMPTION[1]

Pollutant	Averaging Time	Maximum Impact ($\mu g/m^3$)	Monitoring Significance Level ($\mu g/m^3$)	Monitoring Required
SO_2[2]	24-hr	1.5	13	No
PM	24-hr	0.1	10	No
NO_x	Annual	0.03	14	No
CO	8-hr	1.0	575	No
O_3	VOC (Emissions Less than 100 TPY)			No
Pb	Quarter	.0000024 (Annual) .000045 (24-hr)	0.1	No
Be	24-hr	.000012	0.001	No
Hg	24-hr	.000015	0.25	No
Fluorides	24-hr	Nil	0.25	No

[1] Results differ slightly from those presented in the Monitoring Exemption Request (GRU 1993) due to the use of final emissions information and updated receptor grids. Currently predicted impacts are the same or lower than those presented in the monitoring exemption request.

[2] Based on 0.25% S in fuel oil.

Source: ENSERCH Environmental, 1994

7.3 SIGNIFICANT IMPACT AREA ANALYSIS

Once the worst-case operating scenarios were defined and the need for monitoring determined, the next step in the analysis was to determine the significant impact area for each pollutant with an associated PSD increment or AAQS. The significant impact area is defined in the *EPA New Source Review Workshop Manual* (EPA, 1990a) as the circular area whose radius is equal to the greatest distance from the proposed source to which modelling shows that the proposed source will have a significant impact, based upon EPA-defined significance values which are pollutant specific (see Ch.17-212.200(63) F.A.C.). The significant impact areas thus define the distances beyond which the impacts from the proposed source will be insignificant and need not be analyzed in conjunction with existing sources. The results of the significant impact area analyses are presented in Table 7-3. The receptor grids used were described in Section 6.6.1, and maximum concentrations for each averaging period for all five years of meteorological data are provided. As indicated in Table 7-3, none of the pollutants were predicted to have significant off-site impacts. Thus, no further air quality analysis is required for any of the criteria pollutants (i.e. no modelling involving existing sources is required).

7.4 SUMMARY OF IMPACTS — PROPOSED SOURCE ONLY

Table 7-2 provides a summary of maximum predicted impacts due to the proposed source alone. However, the maximum short-term values are based on highest predicted concentrations and are not relevant for comparison with PSD increments and AAQSs which allow one short-term exceedance per year. A summary of maximum off-site impacts using highest annual and highest, second-highest short-term concentrations for the proposed source alone is presented in Table 7-4. As indicated in Table 7-4, maximum off-site impacts for all pollutants are well below the allowable PSD increments, NAAQSs, and FAAQs.

7.5 IMPACTS ON CLASS I AREAS

The potential impacts of the proposed CT on the nearest Class I PSD areas were evaluated in accordance with the procedures outlined in Section 6.6. For this analysis worst-case emissions (100 percent load at 20°F on distillate fuel oil) for short-term impacts were assumed. The ISCST2 model was run with all five years of meteorological data to determine whether the impacts would exceed the PSD Class I significance criteria suggested by the National Park Service (NPS). This modelling was conducted for the Okefenokee National

TABLE 7-3
SUMMARY OF WORST-CASE OFF-SITE IMPACTS VERSUS CLASS II PSD SIGNIFICANCE VALUES

Page 1 of 2

Pollutant	Averaging Time	Emission Rate (g/s)	Ambient Temperature (°F)	CT Load (%)	Year	Normalized[1] Impact ($\mu g/m^3$)	Maximum Impact ($\mu g/m^3$)	Class II Significance Value ($\mu g/m^3$)
SO_2[2]	Annual	7.25	20	80	85	.00257	0.01863	1
					86	.00227	0.01646	
					87	.00239	0.01733	
					88	.00257	0.01863	
					89	.00246	0.01784	
	24-Hour	28.24	20	80	85	.03910	1.1042	5
					86	.03405	0.9616	
					87	.03986	1.1256	
					88	.04025	1.1367	
					89	.05223	1.4750	
	3-Hour	20.74	75	60	85	.20018	4.1517	25
					86	.18534	3.8440	
					87	.19481	4.0404	
					88	.17011	3.5281	
					89	.18529	3.8429	
PM_{10}	Annual	0.62	95	60	85	.00309	0.00192	1
					86	.00276	0.00171	
					87	.00286	0.00177	
					88	.00331	0.00205	
					89	.00313	0.00194	
	24-Hour	1.89	95	60	85	.04638	0.08766	5
					86	.03973	0.07509	
					87	.04964	0.09382	
					88	.05199	0.09826	
					89	.06108	0.11544	

TABLE 7-3
SUMMARY OF WORST-CASE OFF-SITE IMPACTS VERSUS CLASS II PSD SIGNIFICANCE VALUES

Page 2 of 2

Pollutant	Averaging Time	Emission Rate (g/s)	Ambient Temperature (°F)	CT Load (%)	Year	Normalized(1) Impact (µg/m³)	Maximum Impact (µg/m³)	Class II Significance Value (µg/m³)
PM_{10}	8-Hour	1.89	95	60	85	.10987	0.20765	N/A
					86	.09372	0.17713	
					87	.12205	0.23067	
					88	.09546	0.18046	
					89	.13702	0.25897	
CO	8-Hour	7.95	20	60	85	.10005	0.79540	500
					86	.08489	0.67488	
					87	.12073	0.95980	
					88	.08630	0.68609	
					89	.12577	0.99987	
	1-Hour	7.31	75	60	85	.45575	3.33153	2000
					86	.46655	3.41048	
					87	.48079	3.51457	
					88	.42571	3.11194	
					89	.41337	3.02713	
NO_2	Annual	7.61	20	80	85	.00257	0.01956	1
					86	.00227	0.01727	
					87	.00239	0.01819	
					88	.00257	0.01956	
					89	.00246	0.01872	

(1) Normalized impacts are taken directly from the modelling runs and are based on an emission rate of 1 g/s. Maximum impacts are obtained by multiplying the actual emission rate times the normalized impacts.

(2) Based on 0.25% sulfur in fuel and 10 grains/100 SCF in natural gas.

(3) Although no significance value is given for PM_{10} for this averaging period, these results are presented to support the HAP analysis in Section 7.6.

Notes: Maximum impacts are highest values. Short-term emission rates are for fuel oil and are based on specified load and temperature. Annual emission rates are based on 3,900 hours/year (FOF 2,000 hours/year + NGF 1,510 hours/year + NGFPA 390 hours/year). At the specified temperature and load for fuel oil, 20°F and 100% load for natural gas and ISO conditions and 100% load for power augmentation.

Source: ENSERCH Environmental, 1994

TABLE 7-4
SUMMARY OF MAXIMUM OFF-SITE IMPACT CONCENTRATIONS

Pollutant	Averaging Period	Maximum [1] Predicted Concentration ($\mu g/m^3$)	PSD Increment ($\mu g/m^3$)	FAAQS ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)
Carbon Monoxide	1-Hour	3.2	N/A	40,000	40,000
	8-Hour	0.7	N/A	10,000	10,000
Nitrogen Dioxide	Annual	0.02	25	100	100
Sulfur Dioxide[2]	3-Hour	3.7	512	1,300	1,300
	24-Hour	1.0	91	260	365
	Annual	0.02	20	60	80
Particulate Matter (PM_{10} or TSP) [3]	24-Hour	0.09	37 (30)	150	150
	Annual	0.002	19 (17)	50	50
Sulfuric Acid Mist[2]	24-Hour	0.11	N/A	N/A	N/A

[1] Short-term values are highest, second-highest values for this analysis except for sulfuric acid.

[2] Based on 0.25% sulfur in fuel and 10 grains/100 SCF in natural gas. Future fuel oil will be 0.05% sulfur maximum.

[3] The allowable PSD increment is currently evaluated for TSP whereas the AAQS compliance is evaluated for PM_{10}. As a conservative approach, all project emissions of particulate matter were assumed to be in the form of PM_{10}. The PM_{10} PSD increments which will become effective on 6/3/94 are shown in parentheses.

N/A = Not applicable
FAAQS = Florida Ambient Air Quality Standards
NAAQS = National Ambient Air Quality Standards

Source: ENSERCH Environmental, 1994
Ch.17-272.300 FAC
Ch.17-272.500 FAC
40 CFR 50
Federal Register Vol. 58 No. 105, June 3, 1993, p. 31621-31638

Wilderness Area and the Chassahowitzka National Wilderness Area, the nearest two Class I areas.

The results of this analysis are presented in Table 7-5. As indicated, the maximum predicted impacts of PM_{10} and NO_2 are below the NPS significance values, even using the overly conservative assumption of 3,900 hours per year of operation on distillate fuel oil. Based on 2,000 hours per year of fuel oil with 0.25% sulfur by weight, (the existing fuel supply), the short-term SO_2 impacts are above the NPS significance values. However, as indicated in Section 4, a large percentage of the existing fuel oil supply will be consumed during the initial start-up and testing; subsequently, only very low sulfur fuel oil will be used. The maximum predicted impacts using the very low sulfur fuel oil fall below the NPS significance values, as indicated in Table 7-5. This indicates that the impacts of the proposed project on the Class I areas will be "insignificant" when firing natural gas or very low sulfur fuel oil and no further Class I increment consumption assessments are required.

7.6 HAZARDOUS AIR POLLUTANTS (AIR TOXICS ANALYSIS)

This HAPS analysis follows the FDEP's draft air toxics guidelines as revised by the November 29, 1993 guidance memorandum from Howard Rhodes (Appendix D). Pursuant to this memorandum, the air toxics (HAPS) are limited to those pollutants regulated under Section 112 of the Clean Air Act as amended by Title III of the 1990 amendments. For this project, the applicable HAPS emitted by the combustion turbine are listed in Table 6-4.

For each HAP, the maximum emission rates were based on CT operation at full load and an ambient temperature of 20°F. Maximum CT 8-hour, 24-hour and annual impacts were determined based on a normalized emission rate (1 gram/second) and the ISCST2 dispersion model. Worst-case normalized impacts were obtained from Table 7-3. These were multiplied by HAP emission rates at full load rather than at the partial loads in Table 7-3. This approach resulted in a very conservative analysis.

In the case of formaldehyde, the maximum emission rate was based on the maximum VOC emission rate when firing natural gas. This maximum rate occurred during the power augmentation mode at ISO conditions. The assumption that all the VOC emissions are formaldehyde is conservative based on the Profile 0007, Natural Gas Turbine (EPA, 1990b). In the case of the trace metals, the maximum emission rates were based on fuel oil firing and the AP-42 emission factors in Section 3.1, Table 3.1-7 (EPA, 1993).

TABLE 7-5
SUMMARY OF MAXIMUM CLASS I AREA IMPACTS AT 20°F 100% LOAD ON FUEL OIL

Pollutant	Emissions (g/s)	Averaging Period	Maximum Concentration (µg/m³)		EPA (Virginia) Significance Values (µg/m³)	NPS Significance Values (µg/m³)
			Chassahowitzka	Okefenokee		
Based on 3,900 Hours/Year (.445 of Year) of .25% S Fuel Oil:						
SO_2	14.9	Annual	0.00522	0.00552	0.1	.025
	33.6	24	0.31954	0.34238	0.275	.07
	33.6	3	1.52443	1.34299	1.23	.48
PM_{10}	0.85	Annual	0.00030	0.00030	.27	.08
	1.9	24	0.01807	0.01936	1.35	.33
NO_2	13.3	Annual	0.00466	0.00466	0.1	.025
Based on 2,000 Hours/Year (.228 of Year) of .25% S FOF, 390 hrs/yr of NGFPA and 1,510 hrs/yr of NGF:						
SO_2	15.7	Annual	0.00550	0.00550	0.1	.025
	33.6	24	0.31954	0.34238	0.275	.07
	33.6	3	1.52443	1.34299	1.23	.48
Based on 2,000 Hours/Year (.228 of Year) of .05% S FOF, 390 hrs/yr of NGFPA and 1,510 hrs/yr of NGF:						
SO_2	5.2	Annual	0.00182	0.00182	0.1	.025
	6.68	24	0.06353	0.06807	0.275	.07
	6.68	3	0.30307	0.26700	1.23	.48

Note: Annual emission rates are scaled based on 3,900 or 2,000 hours per year of operation.
SO_2 emission rates based on current fuel oil (0.25% S) and future fuel oil (0.05% S) and natural gas containing 10 grains/100 SCF of total sulfur.

Source: ENSERCH Environmental, 1994

The maximum HAP impacts are summarized in Table 7-6. In all cases, the estimated impacts are below the FDEP's draft no threat levels.

TABLE 7-6
SUMMARY OF HAZARDOUS AIR POLLUTANT IMPACTS

Pollutant	Emission Rate (g/s)[1]	FDEP Draft No Threat Levels			Predicted HAP Impacts			Acceptable (Yes/No)
		8-Hour	24-Hour	Annual	8-Hour	24-Hour	Annual	
Formaldehyde[2]	5.68e-01	1.20e+01	2.88e+00	7.70e-02	7.78e-02	3.47e-02	7.92e-04	Yes
Antimony	3.05e-03	5.00e+00	1.20e+01	3.00e-01	4.18e-04	1.86e-04	2.18e-06	Yes
Arsenic	6.80e-04	2.00e+00	4.80e-01	2.30e-04	9.32e-05	4.15e-05	4.86e-07	Yes
Beryllium	4.58e-05	2.00e-02	4.80e-03	4.20e-04	6.28e-06	2.80e-06	3.27e-08	Yes
Cadmium	5.83e-04	5.00e-01	1.20e-01	5.60e-04	7.99e-05	3.56e-05	4.17e-07	Yes
Chromium	6.52e-03	5.00e-01	1.20e-01	8.30e-05	8.93e-04	3.98e-04	4.66e-06	Yes
Cobalt	1.26e-03	5.00e-01	1.20e-01	N/A	1.73e-04	7.70e-05	9.00e-07	Yes
Lead	8.05e-03	5.00e-01	1.20e-01	9.00e-02	1.10e-03	4.92e-04	5.75e-05	Yes
Manganese	4.72e-02	5.00e+01	1.20e+01	4.00e-01	6.47e-03	2.88e-03	3.37e-08	Yes
Mercury	1.26e-04	1.00e-01	2.40e-02	3.00e-01	1.73e-05	7.70e-06	9.00e-04	Yes
Nickel	1.66e-01	1.00e+00	2.40e-01	N/A	2.27e-02	1.01e-02	1.19e-07	Yes
Selenium	7.35e-04	2.00e+00	4.80e-01	N/A	1.01e-05	4.49e-05	5.25e-07	Yes

(1) Annual emission rates scaled to 3,900/8,760 for formaldehyde and to 2,000/8,760 for all others.
(2) Based on VOC emission rate for natural gas firing. Assumes all VOC is formaldehyde.

Normalized Impacts (i.e., impacts based on emissions of 1 g/s): Maximum 8-hour - 0.13702 µg/m^3
Maximum 24-hour - 0.06108 µg/m^3
Annual - 0.00313 µg/m^3

Source: ENSERCH Environmental, 1994

Section VIII

8.0 ADDITIONAL IMPACTS ANALYSIS

8.1 INTRODUCTION

The PSD guidelines indicate that, in addition to demonstrating that the proposed source will neither cause nor contribute to violations of the applicable PSD increments and AAQS, an additional impacts analysis must be conducted for those pollutants subject to PSD review. As indicated in Table 3-4, for this project these pollutants are NO_X, SO_2, PM, and sulfuric acid mist. The additional impacts analysis addresses air quality impacts due to growth induced by the project and air quality impacts on soils, vegetation, and visibility. Furthermore, consideration is given to the HAPS (trace metals) that will be emitted by the project in small quantities rather than restricting the analyses to those pollutants subject to PSD review.

The visibility, vegetation, and soils additional impacts analysis focuses on nearby Class I areas. As has been demonstrated in Section 7.0 of this application, the proposed project will neither cause nor contribute to violations of the Class I PSD increments (nor the AAQS) at the Okefenokee Wilderness Area, located 90 km to 145 km from the proposed source and Chassahowitzka Wilderness Area, located 110 to 129 km from the proposed source. Therefore, the additional impacts analysis section is limited to brief discussions of the issues at these distant locations.

8.2 IMPACTS DUE TO PROJECT-RELATED GROWTH

The growth analysis considers air quality impacts due to emissions resulting from the industrial, commercial, and residential growth associated with the project. Only impacts related to permanent growth are considered; emissions from temporary sources and mobile sources are not addressed in the growth analysis.

There will be an average construction work force of 35 people with a peak work force of 120 required during the nine month construction period. It is anticipated that the majority of the construction workers will commute from their current residences. There will be no additional permanent jobs created by this project.

Development of industries supporting the new CT facility are expected to be negligible. Raw materials consumed by the facility (fuels, supplies, etc.) will be delivered to the site in usable form from outside of the region. Further processing, such as water treatment, will be accomplished entirely on site.

In summary, there will be no residential growth associated with the GRU project and there is little potential for new industrial development nearby as a result of the new facility. Although it is not possible to reliably quantify the secondary emissions and ambient air quality impacts resulting from the proposed project, these impacts are expected to be extremely small and well-distributed throughout the area.

8.3 VISIBILITY IMPACTS

Section 169A of the CAA Amendments of 1977 provide for implementation of guidelines to prevent visibility impairment in mandatory PSD Class I areas. The guidelines are intended to protect the aesthetic quality of these pristine areas from reduction in visual range and atmospheric discoloration due to various pollutants. Potential project impacts on visibility in the nearest Class I areas, the Okefenokee National Wilderness Area and the Chassahowitzka National Wilderness Area, were estimated using the VISCREEN Version 1.01 (88341) model (EPA, 1988b) recommended in the *Guideline to Air Quality Models* (Revised) (EPA, 1993a), impacts were calculated for PM and NO_2 in accordance with the model guidance and using the recommended defaults for the model.

The results of the VISCREEN analysis are presented in Figures 8-1 and 8-2. Based on these results, visible plumes from the project will not significantly impair visibility in the Okefenokee Wilderness Area or the Chassahowitzka Wilderness Area.

Visibility was also evaluated using the methodology presented in the *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase I Report: Interim Recommendation for Modeling Long Range Transport and Impacts on Regional Visibility* (EPA, 1993c). The IWAQM methods are intended to provide for an evaluation of the contributions of NO_x, SO_2, and PM emissions from a project to regional haze using a screening modelling methodology, and, if warranted, more complex modelling. The method accounts for chemical reactions of NO_x and SO_2 with NH_4 in the atmosphere to form particulates which are added to the primary PM_{10} emissions to produce regional haze. Since this IWAQM visibility evaluation was based on interim recommendations, Mr. John Viemont of the National Park Service Research Branch - Air Quality Division was contacted to obtain the most current changes to the methodology (Viemont, 1994). Mr. Viemont recommended that NO_x not be utilized in the evaluation because on the east coast there is typically insufficient ammonia gas (NH_3) available in the atmosphere to react with the nitrate (NO_3^-) and that any NH_3 that is available will preferentially react with the sulfate ($SO_4^=$) to form ammonium sulfate ($(NH_4)_2SO_4$). Another

```
             Visual Effects Screening Analysis for
               Source: DEERHAVEN STATION NEW CT
               Class I Area: OKEFENOKEE NWA


               ***   Level-1 Screening   ***
Input Emissions for

   Particulates     1.90  G  /S
   NOx (as NO2)    29.80  G  /S
   Primary NO2       .00  G  /S
   Soot              .00  G  /S
   Primary SO4       .00  G  /S


    **** Default Particle Characteristics Assumed

             Transport Scenario Specifications:

    Background Ozone:                   .04 ppm
    Background Visual Range:          25.00 km
    Source-Observer Distance:         90.00 km
    Min. Source-Class I Distance:     90.00 km
    Max. Source-Class I Distance:    145.00 km
    Plume-Source-Observer Angle:      11.25 degrees
    Stability:   6
    Wind Speed:   1.00 m/s

                          R E S U L T S

Asterisks (*) indicate plume impacts that exceed screening criteria

         Maximum Visual Impacts INSIDE  Class I Area
          Screening Criteria ARE NOT Exceeded
                                           Delta E      Contrast
                                         ===========  ============
Backgrnd Theta Azi Distance Alpha Crit   Plume   Crit  Plume
======== ===== === ======== ===== ====   =====   ====  =====
 SKY       10.  84.   90.0    84.  2.00    .069    .05  -.000
 SKY      140.  84.   90.0    84.  2.00    .021    .05  -.001
 TERRAIN   10.  84.   90.0    84.  2.00    .003    .05   .000
 TERRAIN  140.  84.   90.0    84.  2.00    .001    .05   .000


         Maximum Visual Impacts OUTSIDE Class I Area
          Screening Criteria ARE NOT Exceeded
                                           Delta E      Contrast
                                         ===========  ============
Backgrnd Theta Azi Distance Alpha Crit   Plume   Crit  Plume
======== ===== === ======== ===== ====   =====   ====  =====
 SKY       10.  75.   87.1    94.  2.00    .072    .05  -.000
 SKY      140.  75.   87.1    94.  2.00    .022    .05  -.001
 TERRAIN   10.  60.   82.3   109.  2.00    .005    .05   .000
 TERRAIN  140.  60.   82.3   109.  2.00    .001    .05   .000
```

Source: ENSERCH Environmental, 1994

GRU	VISCREEN Modelling Output Okefenokee NWA	FIGURE 8-1

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                    Visual Effects Screening Analysis for
                      Source: DEERHAVEN STATION NEW CT
                      Class I Area: CHASSAHOWITZKA NWA


                         ***    Level-1 Screening    ***
    Input Emissions for

       Particulates      1.90  G  /S
       NOx (as NO2)     29.80  G  /S
       Primary NO2        .00  G  /S
       Soot               .00  G  /S
       Primary SO4        .00  G  /S


        **** Default Particle Characteristics Assumed

                    Transport Scenario Specifications:

        Background Ozone:                      .04 ppm
        Background Visual Range:             25.00 km
        Source-Observer Distance:           110.00 km
        Min. Source-Class I Distance:       110.00 km
        Max. Source-Class I Distance:       129.00 km
        Plume-Source-Observer Angle:         11.25 degrees
        Stability:   6
        Wind Speed:   1.00 m/s

                                 R E S U L T S

    Asterisks (*) indicate plume impacts that exceed screening criteria

             Maximum Visual Impacts INSIDE  Class I Area
              Screening Criteria ARE NOT Exceeded
                                                Delta E       Contrast
                                              ===========   ============
    Backgrnd Theta Azi Distance Alpha Crit  Plume   Crit  Plume
    ======== ===== === ======== ===== ====  =====   ====  =====
     SKY       10.  84.  110.0    84.  2.00   .023    .05  -.000
     SKY      140.  84.  110.0    84.  2.00   .007    .05  -.000
     TERRAIN   10.  84.  110.0    84.  2.00   .001    .05   .000
     TERRAIN  140.  84.  110.0    84.  2.00   .000    .05   .000


             Maximum Visual Impacts OUTSIDE Class I Area
              Screening Criteria ARE NOT Exceeded
                                                Delta E       Contrast
                                              ===========   ============
    Backgrnd Theta Azi Distance Alpha Crit  Plume   Crit  Plume
    ======== ===== === ======== ===== ====  =====   ====  =====
     SKY       10.  75.  106.5    94.  2.00   .024    .05  -.000
     SKY      140.  75.  106.5    94.  2.00   .007    .05  -.000
     TERRAIN   10.  60.  100.6   109.  2.00   .001    .05   .000
     TERRAIN  140.  60.  100.6   109.  2.00   .000    .05   .000
```

Source: ENSERCH Environmental, 1994

GRU

VISCREEN Modelling Output
Chassahowitzka NWA

FIGURE
8-2

recommended change to the IWAQM methodology was to utilize 3-hour averages rather than the 1-hour values for SO_2 and PM_{10} suggested in the IWAQM document.

The visibility impact evaluation using this methodology is based on the predicted change in the "deciview" value at the Class I area. The "deciview" is a new visibility index which is a relationship of a constant fractional change in extinction coefficient to perceived visual change (Pitchford and Malm, 1993). A pristine area will have a deciview (dv) value near zero and a one dv change is considered to be a small but perceptible change under many circumstances (CIRA, 1993).

The background of the Okefenokee Wilderness Area is approximately 22.2 dv and the background of the Chassahowitzka Wilderness area is about 21.9 dv (CIRA, 1993). The regional haze evaluation using the IWAQM Level I method utilizing the ISCST2 modelling results indicates that the deciview values may change to 24.1 and 24.0 at the Okefenokee and Chassahowitzka Wilderness Areas, respectively. The calculations used to derive the impacts of the sources are presented in Appendix E.

The results of this alternate method indicated that there would be a 1.9 dv increase at the Okefenokee Wilderness Area and a 2.1 dv change at the Chassahowitzka Wilderness Area. According to the Interagency Monitoring of Protected Visual Environment (IMPROVE) document *Spatial and Temporal Patterns and the Chemical Composition of Haze in the United States: An Analysis of Data from the Improve Network, 1988 - 1991* (CIRA, 1993) these changes would be small but perceptible. However, since the VISCREEN results indicated no visibility impact and since the IWAQM methods are currently only interim recommendations that have not been fully evaluated as to their applicability to the southeastern U.S., it is concluded that the project will not have a significant impact on visibility at either of the Class I areas.

8.4 IMPACT ON SOILS, VEGETATION AND AIR QUALITY RELATED VALUES

Potential air quality impacts of the proposed project were predicted at the PSD Class I Area portions of the Chassahowitzka National Wilderness Area and the Okefenokee National Wilderness Area. In addition to an evaluation of the effects on soils and vegetation, an Air Quality Related Values (AQRV) analysis is typically conducted to assess the potential risk to AQRV's of the two wilderness areas. The National Park Service and the Fish and Wildlife Service were contacted for guidance on the selection and analysis of AQRV's. Based on the distance of the proposed project to either the Chassahowitzka or the Okefenokee National

Wilderness Areas and the proposed emissions of SO_2 and NO_x, these agencies indicated that an AQRV analysis would not be necessary (Porter, 1994).

In order to evaluate the effects of SO_2 and NO_x on vegetation and soils in the impact area, a screening approach was used which compared the maximum predicted ambient concentrations of air pollutants of concern in the Chassahowitzka and Okefenokee National Wilderness Areas with effect threshold limits as reported in the scientific literature. During this evaluation, it was recognized that effect threshold values are not available for all species found in either the Chassahowitzka or the Okefenokee National Wilderness Area. However, studies have been performed on a few of the common species and on other similar species which can be used as models. The contribution from the proposed project was predicted using the ISCST2 model and five years of meteorological data as described in Sections 6.0 and 7.0.

8.4.1 Vegetation

The effects of air contaminants on vegetation occur primarily from sulfur dioxide, nitrogen dioxide, and particulates and are dependent both on the concentration of the contaminant and duration of the exposure. The term "injury", as opposed to "damage", is commonly used to describe all plant responses to air contaminants and will be used in the context of this analysis. The maximum predicted impacts due to the proposed project for the 3-hour, 24-hour, and annual averaging periods are presented in Table 7-5. Each of these incremental levels due to the proposed project are extremely low especially in comparison to reported injury threshold levels. Existing background levels in the Chassahowitzka and the Okefenokee would have to be similar to those found in urban areas in order for the incremental increase from the proposed project to have an adverse effect on vegetation.

8.4.1.1 Sulfur Dioxide/Sulfuric Acid Mist

SO_2 is the air contaminant with the highest predicted emission level for the proposed project. The predicted maximum ground level 3-hour, 24-hour, and annual mean SO_2 concentrations due to the proposed project are 1.5, 0.32, and 0.005 $\mu g/m^3$ in the Chassahowitzka and 1.34, 0.34, and 0.005 $\mu g/m^3$ in the Okefenokee. In comparison, the 1-hour, 3-hour, and annual injury threshold concentrations as reported in the literature are 1,300, 400, and 118 $\mu g/m^3$. Existing annual average background concentrations would have to be in excess of 100 $\mu g/m^3$ to exceed the annual injury threshold concentrations when combined with the contribution of the proposed project. According to previous studies and from ambient monitoring data from regional air quality monitoring locations, annual background concentrations of SO_2 are in the range of 3-9 µg/m^3. Accordingly, no effects on vegetation are anticipated from the SO_2 levels from the proposed project.

The limited information available in the scientific literature suggests that sulfuric acid mist concentrations in excess of 100 µg/m^3 may have adverse effects on vegetation. The estimated concentration from the proposed project is 0.0357 µg/m^3 which is well below the value reported in the literature. Accordingly, there is no effect associated with the proposed project.

8.4.1.2 Nitrogen Dioxide

The maximum annual NO_2 concentration predicted to occur as a result of the proposed project in the Chassahowitzka and Okefenokee is 0.0047 µg/m^3. Assuming a background concentration of 10-13 µg/m^3 based on regional air quality monitoring data and an annual average injury threshold value of 470 µg/m^3, the predicted increase due to operation of the proposed project would not result in levels of NO_2 that would be injurious to vegetation.

8.4.1.3 Particulates

The maximum predicted ground-level 24-hour and annual concentrations of particulates (in the form of PM_{10}) due to the proposed project are 0.018 and 0.0003 µg/m^3 for the Chassahowitzka and 0.019 and 0.0003 µg/m^3 for the Okefenokee. Based on regional monitoring data, an annual background range of 18-29 µg/m^3 is estimated for particulates. No effects on vegetation are anticipated when the predicted concentrations from the proposed project are added to the estimated background concentrations, since these concentrations are below injury threshold values reported in the literature.

8.5 SOILS

Air contaminants can affect soils through fumigation by gaseous forms, accumulation of compounds transformed from the gaseous state, or by the direct deposition of particulate matter. Concentrations of SO_2 and NO_2 several orders of magnitude higher than the predicted values are required before any adverse effects from fumigation are observed. It is more likely that effects on soils could occur from the deposition of trace elements (mostly trace metals) in particulate matter. However, the predicted concentrations of particulate matter from the proposed project are so infinitesimally small that potential effects on soils are not anticipated.

Section IX

9.0 CONCLUSION

The proposed project will apply BACT to control its emissions, will meet other state emission requirements, will comply with AAQS and PSD increment requirements, will not cause exceedances of FDEP's draft No Threat Levels, and will not cause any other significant air quality problems. Therefore, reasonable assurances have been provided to support FDEP's issuance of a PSD permit for the project.

Section X

10.0 REFERENCES

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APPENDIX A

GE DATA SHEETS

GE Power Generation Engineering

Project Engineering
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One River Road, Schenectady, NY 12345 USA
Phone: (518) 385-9219 Dial Comm: 8*235-9219
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Date: October 6, 1993

Copies:

R Schubert	2-433
M Cardano	Tampa Office
J. Hudson	GVL-156
R Phelan	37-2 Annex
File/LB	

Subject: **Gainesville Regional Utilities (GRU) DM#GR0292 Performance/Emissions Request**

To: Tom Putman
EBASCO Services Inc.
Atlanta Office
145 Technology Park
Atlanta, GA 30092

Enclosed are the performance/emissions tables you requested last month. Per M Cardano's telecon with Doug Beck of GRU only base load emissions at 95 F will be guaranteed, except for NOx which is guaranteed at all load points in the attached tables. All other emissions values are estimated and may be used for information. While we don't expect the reported values to vary significantly, some values may change as the DLN combustion system, including the control system and operating scheme get fine tuned.

Three changes have occurred to the fuel oil runs since we originally submitted performance data in our proposal. First the water injection rates on oil fuel have been adjusted downward, based on latest test data on the DLN combustor. You will note some related changes in the performance which are directly related to water injection rate. Second, since GRU has requested estimated NOx with extremely high fuel bound nitrogen (0.14% by wt.) we have increased our estimated yield (ratio of nitrogen in fuel to NOx produced organically in exhaust). Therefore the first number under NOx for the distillate runs reflects expected NOx with 0.14% (by weight) fuel bound nitrogen (100 ppmvd @ 15% O2, of which 42 ppmvd is thermal NOx and the remaining 58 ppmvd is organic NOx) and the second number is expected NOx with 0.03% fuel nitrogen, as you requested. Lastly the two numbers in the sulfur emissions row on the distillate runs reflect the original 0.46% (by weight) fuel sulfur and the second number reflects the lower 0.05% (by weight) fuel sulfur level.

Michael A. Davi

Michael A. Davi, Project Leader
GT Applications Engineering

md/enclosure

Case: [illegible]tural Gas , Dry Low NO_x Combustor
Inlet Guide Vane Position 100% Open @ Base Only

Load Level - %	100	80	60	100	80	60
Ambient Temperature - °F	20	20	20	75	75	75
Relative Humidity - %	100	100	100	90	90	90
Gross Output - kW (at Gen. Terminals)	94340	75230	56420	78760	63050	47250
Auxiliary Power and Losses - kW (GT)	450	450	450	450	450	450
Net Output - kW	93890	74780	55970	78310	62600	46800
Firing Temperature - °F (Nom)	2020	2007	2000	2020	2009	2002
Net Heat Rate (HHV) - Btu/kWh	11440	12100	13850	11900	12790	14780
Heat Cons. (HHV) $x10^6$ - Btu/hr	1074.5	896.0	760	931.1	792.9	672.1
Exhaust Mass Flow $x10^3$ - lb/hr	2550	2087	1753	2247	1869	1580
Exhaust Temp - °F	964	988	1037	1001	1037	1086
Water Injection Flow - lb/hr	0	0	0	0	0	0
Fuel Flow - lb/hr	41990	37520	31810	38990	33210	28390
Exhaust Analysis						
NO_x - ppmvd @ 15% O_2	15	15	15	15	15	15
NO_x as NO_2 - lb/hr	58	49	41	51	43	37
CO - ppmvd	15	15	15	15	15	15
CO - lb/hr	35	29	24	31	26	21
Total VOC - ppmvw	2	2	2	2	2	2
Total VOC - lb/hr	3	3	3	2.7	2.7	2.7
Non Methane HC - ppm	2	2	2	2	2	2
Non Methane HC - lb/hr	3	3	3	2.7	2.7	2.7
Particulate - lb/hr	7	7	7	7	7	7
Particulate - PM_{10} lb/hr	7	7	7	7	7	7
Particulate - TSP lb/hr	7	7	7	7	7	7
SO_2 - ppmvd	Trace					
SO_2 - lb/hr	Trace					
SO_3 - ppmvw	Trace					
SO_3 - lb/hr	Trace					
Opacity - %	10	10	10	10	10	10
Argon Ar - % Vol	0.90	0.91	0.90	0.90	0.88	0.88
Nitrogen N_2 - % Vol	75.36	75.32	75.32	73.68	73.62	73.62
Oxygen O_2 - % Vol	13.93	13.86	13.85	13.64	13.53	13.50
Carbon Dioxide CO_2 - % Vol	3.22	3.20	3.21	3.09	3.14	3.15
Water H_2O - % Vol	6.59	6.71	6.72	8.70	8.83	8.85

Ca Natural Gas , Dry Low NO_x Combustor
Inlet Guide Vane Position 100% Open @ Base Only

Load Level - %	100	80	60	100	90	80	60
Ambient Temperature - °F	95	95	95	ISO	ISO	ISO	ISO
Relative Humidity - %	50	50	50	ISO	ISO	ISO	ISO
Gross Output - kW (at Gen. Terminals)	72030	58980	44130	82810	75050	66620	50070
Auxiliary Power and Losses - kW	450	450	450	450	450	450	450
Net Output - kW	71580	58530	43680	82360	74600	66170	49620
Firing Temperature - °F (Nom)	2020	2010	2008	2020	2013	2007	2002
Net Heat Rate (HHV) - Btu/kWh	12130	13090	15160	11790	11940	12550	14420
Heat Cons. (HHV) $x10^6$ - Btu/hr	868.3	758.8	649	971.1 ~~875~~	886	821.5	701.9
Exhaust Mass Flow $x10^3$ - lb/hr	2137	1795	1530	2343	2100	1937	1636
Exhaust Temp - °F	1011	1058	1100	989	1005	1022	1072
Water Injection Flow - lb/hr	0	0	0	0	0	0	0
Fuel Flow - lb/hr	~~37500~~ 36400 DJA	31800	27200	40700	37140	34420	29410
Exhaust Analysis							
NO_x - ppmvd @ 15% O_2	15	15	15	15	15	15	15
NO_x as NO_2 - lb/hr	47	41	35	53	48	44	38
CO - ppmvd	15	15	25	15	15	15	15
CO - lb/hr	29	24	35	32	29	27	23
Total VOC - ppmvw	2	2	2	2	2	2	2
Total VOC - lb/hr	2.6	2.6	2.6	2.8	2.8	2.8	2.8
Non Methane HC - ppm	2	2	2	2	2	2	2
Non Methane HC - lb/hr	2.6	2.6	2.6	2.8	2.8	2.8	2.8
Particulate - lb/hr	7	7	7	7	7	7	7
Particulate - PM_{10} lb/hr	7	7	7	7	7	7	7
Particulate - TSP lb/hr	7	7	7	7	7	7	7
SO_2 - ppmvd	Trace						→
SO_2 - lb/hr	Trace						→
SO_3 - ppmvw	Trace						→
SO_3 - lb/hr	Trace						→
Opacity - %	10	10	10	10	10	10	10
Argon Ar - % Vol	0.88	0.89	0.88	0.90	0.89	0.90	0.90
Nitrogen N_2 - % Vol	73.61	73.53	73.54	74.91	74.88	74.86	74.86
Oxygen O_2 - % Vol	13.72	13.53	13.55	13.93	13.84	13.83	13.80
Carbon Dioxide CO_2 - % Vol	3.09	3.13	3.12	3.11	3.16	3.16	3.17
Water H_2O - % Vol	8.71	8.95	8.91	7.15	7.23	7.25	7.27

Ca[illegible]atural Gas , Dry Low NO_x Combustor, Powe[illegible]ugmentation

Inlet Guide Vane Position 100% Open @ Base Only

Load Level - %	100	100	90	80	60		
Ambient Temperature - °F	95	ISO	ISO	ISO	ISO		
Relative Humidity - %	50	ISO	ISO	ISO	ISO		
Gross Output - kW (at Gen. Terminals)	78710	89580					
Auxiliary Power and Losses - kW	450	450					
Net Output - kW	78260	89130					
Firing Temperature - °F (Nom)	2020	2020					
Net Heat Rate (HHV) - Btu/kWh	12600	12300					
Heat Cons. (HHV) $x10^6$ - Btu/hr	986.1	1096.6					
Exhaust Mass Flow $x10^3$ - lb/hr	2189	2396					
Exhaust Temp - °F	1014	990					
Water Injection Flow - lb/hr	51370	56920					
Fuel Flow - lb/hr	42590	45920					
Exhaust Analysis							
NO_x - ppmvd @ 15% O_2	30	30					
NO_x as NO_2 - lb/hr	107	120					
CO - ppmvd	20	20					
CO - lb/hr	38	42					
Total VOC - ppmvw	3	3					
Total VOC - lb/hr	4	4.5					
Non Methane HC - ppm	3	3					
Non Methane HC - lb/hr	4	4.5					
Particulate - lb/hr	7	7					
Particulate - PM_{10} lb/hr	7	7					
Particulate - TSP lb/hr	7	7					
SO_2 - ppmvd	Trace	→					
SO_2 - lb/hr	Trace	→					
SO_3 - ppmvw	Trace	→					
SO_3 - lb/hr	Trace	→					
Opacity - %	10	10					
Argon Ar - % Vol	0.85	0.86					
Nitrogen N_2 - % Vol	70.64	71.85					
Oxygen O_2 - % Vol	12.36	12.57					
Carbon Dioxide CO_2 - % Vol	3.37	3.43					
Water H_2O - % Vol	12.78	11.29					

No power aug. when below base.

Ca[illegible] Fuel Oil, Dry Low NO_x Combustor
Inlet Guide Vane Position 100% Open @ Base Only

Load Level - %	100	80	60	100	80	60	
Ambient Temp - °F	20	20	20	75	75	75	
Relative Humidity - %	100	100	100	90	90	90	
Gross Output - kW	96940	77660	58110	80280	64150	48190	
Auxiliary Power and losses- kW	475	475	475	475	475	475	
Net Output - kW	96415	77185	57635	79805	63675	47715	
Firing Temperature - °F (Nom)	2020	2000	1990	2020	2000	1990	
Net Heat Rate (HHV) - Btu/kWh	11400	12120	13850	11760	12650	14540	
Heat Cons. (HHV) $x10^6$ - Btu/hr	1100	926	782.9	938.6	798	680	
Exhaust Flow $x10^3$ - lb/hr	2610	2055	1741	2295	1864	1596	
Exhaust Temp - °F	955	1001	1068	994	1050	1086	
Water Injection Flow - lb/hr	45070	37150	30060	31640	25310	20050	
Fuel Flow - lb/hr	55940	47100	39820	47740	40600	34600	
Exhaust Analysis FBN							
* NO_x - ppmvd @ 15% O_2 (0.4%)/(0.03%)	100/54	100/54	100/54	100/54	100/54	100/54	
NO_x as NO_2 - lb/hr	437/237	365/197	307/166	372/201	315/170	266/144	
CO - ppmvd	30	30	40	30	30	40	
CO - lb/hr	71	56	63	62	50	58	
VOC - ppmvw	5	5	5	5	5	5	
VOC - lb/hr	7	6	5	6	5	5	
Sulfuric Acid Mist - lb/hr (0.46%/0.05%)	51/6	44/5	37/4	44/5	37/4	32/4	
Particulate - PM_{10} lb/hr	15	15	15	15	15	15	
Particulate - TSP lb/hr	15	15	15	15	15	15	
SO_2 - ppmvd (0.46% / 0.05%	85/10	90/10	90/10	83/9	85/9	85/9	
SO_2 - lb/hr " / "	490/53	411/45	348/38	416/45	354/39	301/33	
SO_3 - ppmvw " / "	5/1	5/1	5/1	5/1	5/1	5/1	
SO_3 - lb/hr " / ")	30/3	28/3	23/3	29/3	23/3	21/3	
Opacity - %	20	20	20	20	20	20	
Argon Ar - % Vol	0.88	0.90	0.89	0.87	0.88	0.88	
Nitrogen N_2 - % Vol	73.85	73.64	73.75	72.63	72.58	72.72	
Oxygen O_2 - % Vol	13.16	12.70	12.80	13.04	12.80	12.92	
Carbon Dioxide CO_2 - % Vol	4.35	4.60	4.56	4.21	4.35	4.30	
Water H_2O - % Vol	7.76	8.17	8.00	9.25	9.39	9.18	

* 42 ppmvd @ 15% O_2 if FBN ≤ 0.015% by wt.

Cas.. uel Oil, Dry Low NO_x Combustor

Inlet Guide Vane Position 100% Open @ Base Only

Load Level - %	100	80	60	100	90	80	60
Ambient Temp - °F	95	95	~~90~~95	ISO	ISO	ISO	ISO
Relative Humidity - %	50	50	50	ISO	ISO	ISO	ISO
Gross Output - kW	74370	59410	44620	85580	76990	68520	51370
Auxiliary Power and losses- kW	475	475	475	475	475	475	475
Net Output - kW	73895	58935	44145	85105	76515	68045	50895
Firing Temperature - °F (Nom)	2020	2010	1990	2020	2008	2000	1995
Net Heat Rate (HHV) - Btu/kWh	11960	12940	14920	11640	11950	12470	14300
Heat Cons. (HHV) $x10^6$ - Btu/hr	883.7	755.7	646.1	990.6	905	840	714
Exhaust Flow $x10^3$ - lb/hr	2178	1798	1548	2390	2093	1927	1644
Exhaust Temp - °F	1007	1058	1092	981	1020	1042	1080
Water Injection Flow - lb/hr	29770	23650	18680	39420	35140	31930	25600
Fuel Flow - lb/hr	44940	38430	32860	50380	46030	42740	36310
<u>Exhaust Analysis</u>							
* NO_x - ppmvd @ 15% O_2 (0.14%/0.03%)	100/54	100/54	100/54	100/54	100/54	100/54	100/54
NO_x as NO_2 - lb/hr	351/189	298/161	253/137	394/213	357/193	332/179	279/151
CO - ppmvd	30	30	40	30	30	30	40
CO - lb/hr	59	48	56	65	57	53	60
VOC - ppmvw	5	5	10	5	5	5	10
VOC - lb/hr	6	6	9	6	6	6	9
Sulfuric Acid Mist - lb/hr (0.46%/0.05)	41/5	35/4	30/3	46/5	41/5	39/4	35/4
Particulate - PM_{10} lb/hr	15	15	15	15	15	15	15
Particulate - TSP lb/hr	15	15	15	15	15	15	15
SO_2 - ppmvd (0.46%/0.05%)	81/9	85/9	83/9	83/9	87/10	87/10	87/10
SO_2 - lb/hr (" / ")	393/43	336/37	298/31	439/48	403/44	373/41	318/35
SO_3 - ppmvw (" / ")	5/1	5/1	5/1	5/1	5/1	5/1	5/1
SO_3 - lb/hr (" / ")	25/3	25/3	18/2	30/3	25/3	25/3	21/2.5
Opacity - %	20	20	20	20	20	20	20
Argon Ar - % Vol	0.87	0.87	0.88	0.89	0.88	0.89	0.88
Nitrogen N_2 - % Vol	72.57	72.56	72.71	73.50	73.39	73.40	73.55
Oxygen O_2 - % Vol	13.10	12.93	13.06	13.18	12.91	12.88	12.99
Carbon Dioxide CO_2 - % Vol	4.16	4.27	4.21	4.27	4.43	4.45	4.40
Water H_2O - % Vol	9.30	9.37	9.14	8.17	8.39	8.39	8.18

* 42 ppmvd @ 15% O_2 if FBN ≤ 0.015% by wt.

APPENDIX B

NORTON CHEMICAL SCR COST ESTIMATE

NORTON CHEMICAL PROCESS PRODUCTS CORPORATION

NORTON

P.O. Box 350
Akron, Ohio 44309-0350
(216) 673-5860

November 3, 1993

Ebasco Environmental
759 South Federal Highway
Stuart, Fla 34994-2936

Fax No. (407) 225-9463

Pages: 4

Attn: Darrel Graziani

Re: GE MS7001EG gas turbine
Norton Project Number NC93193

Dear Mr. Graziani:

Norton Company is pleased to submit our preliminary proposal to supply an NC-300 SCR Catalyst System to control NOx emissions from a combustion turbine. We have based our estimate on the 0.14% N fuel oil case, since this represents the worst case condition. The design will cover both the natural gas and fuel oil firing conditions.

A. NC-300 Catalyst System	$ 3,939,000.00

The above price includes:
- NC-300 SCR Catalyst
- CO Oxidation Catalyst
- Catalyst Modules
- Hot Wall Reactor Housing
- Ammonia Injection Grid
- Ammonia Dilution and Flow Control Skid
- Ammonia Storage Tank
- Engineering Specifications
- Continuous Emissions Monitoring System

The system does not include:
- Interconnecting Piping and Wiring
- Field Installation

Please refer to the attached Preliminary Mechanical Design and Performance data sheets labeled NC93193-1 for more details. Please note that our current maximum operating temperature for the NC-300 Catalyst is 1050 Deg F. In the future it may be feasible to extend this to cover the maximum temperatures indicated in your data sheets. Otherwise, we would need to inject ambient air into the exhaust in order to control the maximum temperature limit.

The standard performance warranty for this type of NC-300 SCR System covers the NOx reduction and ammonia slip performance of the system for a period of three years or 24000 operating hours, whichever comes first. The expected catalyst life is three to five years after which time catalyst replacement may become necessary. The expected NC-300 SCR catalyst replacement cost for a reactor of this size is $ 934,731.00 per catalyst layer.

The typical CO oxidation catalyst warranty is one year or 8000 hours, whichever comes first. The estimated CO catalyst replacement cost is $ 750,000.00 per layer.

Thank you for allowing the Norton Company this opportunity to present our products. If you have any questions or additional requirements, please do not hesitate to contact us.

Sincerely,

NORTON Chemical Process Products Corporation

Stephen M. Turner
Manager, Sales and Marketing,
Environmental Products

Customer: Ebasco Environmental
Project Ref: GE MS7001EG gas turbine
Case: 0.14% N fuel oil

SELECTIVE CATALYTIC REDUCTION UNIT

REACTOR DESIGN AND PERFORMANCE CONDITIONS

Norton NC93193-1

1.0 Preliminary Mechanical Design

1.1 Manufacturer — Norton Company

1.2 Arrangement — Horizontal flow

1.3 Catalyst Module nominal dimensions (ft)
height x width x depth CO: 6.0 x 6.0 x 0.5
NOx: 6.50 x 6.50 x 0.82

The CO catalyst bed will be arranged in (1) layer
The NOx catalyst bed will be arranged in (2) layers

1.4 Reactor Inside Dimensions (ft)
height x width x depth CO: 30.0 x 30.0 x 1.0
NOx: 45.5 x 45.5 x 4.0

Total reactor length, including CO, ammonia injection grid and NOx catalyst: 15.0 ft

Reactor dimensions are approximate; depth does not include space for additional catalyst layers

1.5 No. of Catalyst Modules CO: 25
NOx: 98

1.6 Materials of Construction (Hot Wall Reactor)

Catalyst Modules	AISI 304 SS
Module Support Framework	AISI 304 SS
Reactor Housing Wall/Supports	AISI 409 SS
Catalyst Type	NC-300 Zeolite-based 100 cell/sq.in. honeycomb
Insulation	Mineral Wool with 0.016 inch aluminum cover

1.7 Maximum Allowable Catalyst Temp (F) — 1050

1.8 Total Pressure Drop (in H2O) — 6.0

1.9 Notes:

Customer: Ebasco Environmental
Case: 0.14% N fuel oil

SELECTIVE CATALYTIC REDUCTION UNIT

Norton NC93193-1

2.0 Performance

2.1	Gas Flow Rate (wet basis)		
	Exhaust Gas (lb/hr)		2610000
	Exhaust Gas (ACFM)		1601889
2.2	Flue Gas Composition (mole %)		
	Nitrogen (N2)	73.85	
	Carbon Dioxide (CO2)	4.35	
	Water (H2O)	7.76	
	Oxygen (O2)	13.16	
	Argon (AR)	0.88	
	TOTAL PERCENT	100.00	
	SOx (ppmv)		85.0
	Molecular Weight		28.6
	CO (ppmv)		30.0
	Inlet NOx based on exhaust gas flow; as NO2		
	lb/hr		435.1
	ppmvd @ 15.0% O2		100.0
2.3	Flue Gas Temperature (F)		
	Design		981
	Range	955	to 1080
2.4	Flue Gas Pressure Drop (in. H2O)		
	Across CO catalyst		1.5
	Across AIG		0.1
	Across NOx Catalyst		3.0
2.5	Ammonia Consumption (lb/hr 25.0% aq.)		550.9
2.6	Dilution Media Flow Rate		
	Air (SCFM)		881
2.7	Ammonia Slip (ppmv)		< 10
2.8	NOx Conversion Efficiency (%)		76.0
2.9	CO Conversion Efficiency (%)		70.0
2.10	Outlet NOx based on exhaust gas flow; as NO2		
	lb/hr		104.4
	ppmvd @ 15.0% O2		24.0

APPENDIX C

REVISED NORTON CHEMICAL SCR COST ESTIMATE INCLUDING AIR INJECTION

NORTON CHEMICAL PROCESS PRODUCTS CORPORATION

NORTON

P.O. Box 350
Akron, Ohio 44309-0350
(216) 673-5860

FACSIMILE TRANSMISSION COVER SHEET
Norton Fax (216) 677-3609

TO: Ebasco Environmental

DATE: November 23, 1993

ATTN: Darrel Graziani

No. PAGES: 1

FAX: 407-225-9463

REF: GE MS7001EG gas turbine
Norton Project Number NC93193

Dear Mr. Graziani:

In reply to your revised conditions for the subject inquiry, we can revise our previous budgetary quotation as follows:

1. Budget price of Nov. 3, 1993:	$ 3,939,000.00
2. Delete CO oxidation catalyst:	- $ 743,000.00
3. Add exhaust cooling air system:	+ $ 83,000.00
TOTAL REVISED PRICE	$ 3,279,000.00

We estimate the additional cooling air required for the high temperature case (1080 Deg F) will be about 32,000 SCFM. Since the highest temperatures occur at the 60% load condition, the total exhaust flow through the catalyst is still lower than the total flow at 100% load. Thus, the 100% load condition is still the design basis for sizing the catalyst reactor. Our previous reactor sizing would still apply for the revised outlet NOx limits (11.7 ppmv for oil, 3.5 ppmv for natural gas).

I hope this additional information will be helpful. Please let us know how we can be of further assistance as this project proceeds.

Sincerely,

NORTON Chemical Process Products Corporation

Stephen M. Turner
Manager, Sales & Marketing,
Environmental Products

APPENDIX D

FDEP AIR TOXICS MEMORANDUM

Memorandum

Florida Department of
Environmental Protection

TO:	Ed Middleswart	NW District
	Chris Kirts	NE District
	Chuck Collins	Central Florida District
	Bill Thomas	SW District
	David Knowles	South Florida District
	Isidore Goldman	SE District
	Al Linero	Broward County
	H. Patrick Wong	Dade County
	Steve Pace	Duval County
	Iwan Choronenko	Hillsborough County
	Jim Stormer	Palm Beach County
	Peter Hessling	Pinellas County
	J. Kent Kimes	Sarasota County
	Dennis Nester	Orange County
	Dotty Diltz	Bureau of Air Monitoring and Mobile Sources
	Clair Fancy	Bureau of Air Regulation

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

DATE: November 29, 1993

SUBJECT: Air Toxics Program Development and Use of Air Toxics Permitting Strategy

By January 1994, the EPA expects to promulgate eight air toxics rules under Section 112 of the Clean Air Act. Maximum achievable control technology (MACT) standards for as many as 28 source categories are expected to be issued or proposed by the end of 1994. (The first of these standards, for commercial and industrial dry cleaners, was published September 22.) Furthermore, the state must adopt a hazardous air pollutant (HAP) new source review rule and a MACT "hammer" rule by the Fall of 1994 to be eligible to receive delegation of the Title V permitting program.

This memo is to update you on how the Division will be responding to these new requirements organizationally and to identify some of the key issues that will need to be addressed. It is also intended to provide new guidance on use of the "air toxics permitting strategy" modeling methodology.

Air Toxics Subsection

The Air Toxics Subsection in the Office of Policy Analysis and Program Management (SC 278-0114) will continue to be the focal point for all air toxics program development activities. John Glunn will be the lead contact for the overall program, including all grant-related and rulemaking activities. Tom Savage and Beth Hardin will be assigned responsibility for tracking specific EPA activities and disseminating information to other air program staff as needed. For example, Beth is currently analyzing the dry cleaner NESHAP and the proposed "general provisions" of 40 CFR 63; Tom is following the HON and the "early reductions" program.

The Air Toxics Subsection will function primarily as a planning and development group. As elements of the air toxics program (permitting, compliance, source sampling, emissions reporting, and ambient monitoring) become integrated into the operational units of the air program throughout the state, the Air Toxics Subsection will be available to provide technical support.

Florida Air Toxics Working Group (FLATWG)

The Florida air toxics working group was established prior to passage of the Clean Air Act Amendments of 1990 to develop recommendations for a state air toxics control program. Since then, the role of the group has changed. Now, the primary function of FLATWG is to facilitate implementation of the federal air toxics program in Florida. Each district and local air program, as well as the two DARM bureaus, should designate a FLATWG representrative. The Air Toxics Subsection will work through the FLATWG representatives to keep air program staff in all offices informed of air toxics developments and to share ideas on how to respond to the various EPA requirements. The group will continue to hold periodic teleconferences and meet in a half-day session at the Annual Air Meeting.

Air Toxics Program Development Issues

The major issues to be addressed in the development of Florida's air toxics program are as follow:

1. Adoption by reference of federal standards: How should this be handled on an ongoing basis? What, if any, standards should not be adopted? How should implementation of the standards through the permitting process be coordinated? How should compliance with area-source standards be assured?

2. Rule development at state level: How should the Department respond to the need for HAP new source review and MACT hammer rules to obtain Title V delegation, especially in the absence of final EPA rules? What role, if any, should a procedure similar to the current air toxics permitting strategy play in this rulemaking?

3. Accidental release program: What role, if any, should the district and local programs assume in implementation of the Section 112(r) program in Florida? Should routine compliance inspections be used to verify that sources are adhering to their risk management plans?

4. Air toxics assessment: How and to what extent should air toxics assessment activities such as emissions inventories, emission speciation studies, high-risk point source evaluations, ambient monitoring programs, receptor modeling studies, ecosystem assessments, and risk assessments be carried out?

The Air Toxics Subsection, with input from FLATWG, will be considering these issues over the next several months and developing options for our consideration.

Air Toxics Permitting Strategy

Special mention must be made of the "air toxics permitting strategy" and its use in the emerging air toxics program. The strategy was developed several years ago as a tool to assist district and local program air permit engineers in evaluating permit applications that involved significant emissions of hazardous air pollutants. Indeed, the strategy has been effective in addressing air toxics in a flexible manner, and its use was upheld in a permit hearing. At one point, the Division intended to eventually adopt the strategy as part of a state air toxics rule. However, this plan was changed by passage of the Clean Air Act Amendments of 1990.

In the future, the control of HAP emissions in Florida will be dominated by the programs and standards developed under Title III of the Clean Air Act Amendments of 1990. Once the Title V operating permit program is approved by EPA, all Title III permitting requirements will become federally enforceable permit conditions within the Title V permits. On the other hand, any HAP emission limit or work practice standard based on a state program different than Title III (such as our toxics permitting strategy) will not be made a federally enforceable Title V permit condition unless EPA has approved the state program under Section 112(l) of the Act or the applicant accepts the permit condition for other reasons. There are no plans to seek approval of our permitting strategy since it would involve formally adopting the strategy as an alternative to the federal program.

This is not to imply that the strategy will no longer serve a useful purpose. Section 112(g) requires states to develop rules that will require new or modified sources proposing to increase hazardous air pollutant emissions above "de minimis" amounts to undergo case-by-case MACT determinations. How EPA will define "de minimis" is not certain, but it may involve a process that is similar to our strategy. Once a de minimis threshold is exceeded, the case-by-case MACT process may require that ambient concentrations, and resultant health impacts, be considered along with other factors in determining the appropriate MACT standard. Therefore, the strategy continues to reflect incipient agency rulemaking, though the final direction of this rulemaking is uncertain at this time.

In any case, if the air toxics permitting strategy is to function in the context of Title III and Title V, it must be revised. First, it must be viewed as an air toxics "evaluation tool" rather than a "permitting strategy." Second, it must be limited in its application to the 189 hazardous air pollutants currently regulated under Title III and state law. Third, the modeling protocol needs to use the better air dispersion models now available. Fourth, the source of each of the health benchmarks chosen to define a reference ambient concentration must be clear and defensible. Finally, the term "no threat level" must be changed to more accurately reflect the purpose of these values. Anticipate that changes to the strategy in line with these points will be discussed at the Annual Air Meeting.

In the meantime, you may use the strategy as a tool during those preconstruction reviews where an apparent public health threat exists. However, do not consider pollutants other than the 189 currently regulated HAPs. Also, do not use the strategy in the context of operation permit renewals. The "no threat levels" are not environmental standards; therefore, a predicted concentration in excess of any such level is not an automatic grounds for permit denial. Other factors, such as the reasonableness of the proposed control technology should be considered.

If you wish to discuss these issues further, please call John Glunn at 904/488-0114.

HLR/jg/p

cc: Larry George
John Glunn
Tom Savage
Beth Hardin
Tom Rogers

APPENDIX E

IWAQM VISIBILITY CALCULATIONS

GAINESVILLE REGIONAL UTILITES
DEERHAVEN STATION
NEW 74 MW CT

Class I Visibility calculations per IWQAM Document
Appendix B - Method for Calculating Regional Visibility Impairment

SO_2 Maximum 3-hour average at the Chassakowitzka NWA 0..30307 ug/m^3

PM_{10} Maximum 3-hour average at the Chassakowizka NWA 0..08620 ug/m^3

$SO_4^=$ equals 1.5 times SO2 per page 5-5 of IWAQM Document

$$1.5 \cdot 0.30307 = 0.45461$$

NH_4SO_2 equals 1.375 times $SO_4^=$ per Appendix B of IWAQM Documnet

$$NH_4SO_2 = 1.375 \cdot 0.45461 = 0.62509$$

$[b_{ext.s}] = 0.003 * \{part\} * fRH$ This formula is from page B-1 of the IWAQM Document

Where: $b_{ext.s}$ = the extinction coefficient due to particle scattering (km^{-1})
0.003 = a nominal dry scattering efficiency
{part} = the particulate concentration in ug/m3
fRH = the RH correction factor (11.5 at the assumed rh of 95%)
(fRh is set to 1 for fine particulates p B-2 IWAQM Document)
(the fRH is from page B-3 of the IWAQM Document)

$$NH_4SO_2(b_{ext}) = 0.003 \cdot 0.62509 \cdot 11.5 = 0.02157$$

$$PM_{10}(b_{ext}) = 0.003 \cdot 0.08620 \cdot 1 = 0.00026$$

$$\text{Total of } NH_4SO_2 \text{ and } PM_{10} = 0.02157 + .00026 = 0.02183$$

$$dv = 10\ln(b_{ext} / 0.01\ km^{-1})$$

Where: dv = Deciviews
b_{ext} = the extinction coefficient (km^{-1})

$$dv(\text{contribution from source}) = 10 \cdot \ln\left(\frac{0.02183}{0.01}\right) = 7.8$$

background extinction coefficient from IMPROVE Document page S-7 figure S.2(a)
89 Mm^{-1} = 0.089 km^{-1}

$$dv(\text{background}) = 10 \cdot \ln\left(\frac{0.089}{0.01}\right) = 21.9$$

$$dv(\text{background + source}) = 10 \cdot \ln\left[\frac{(0.0890 + 0.02183)}{0.01}\right] = 24.1$$

Difference of (background + source) minus Background (dv) = $24.1 - 21.9 = 2.2$

GAINESVILLE REGIONAL UTILITES
DEERHAVEN STATION
NEW 74 MW CT

Class I Visibility calculations per IWQAM Document
Appendix B - Method for Calculating Regional Visibility Impairment

SO_2 Maximum 3-hour average at the Okeefenokee NWA 0.26700 ug/m^3

PM_{10} Maximum 3-hour average at the Okeefenokee NWA 0.07594 ug/m^3

$SO_4^=$ equals 1.5 times SO2 per page 5-5 of IWAQM Document

$$1.5 \cdot 0.26700 = 0.4005$$

NH_4SO_2 equals 1.375 times $SO_4^=$ per Appendix B of IWAQM Documnet

NH_4SO_2= $1.375 \cdot 0.4005 = 0.55069$

$[b_{ext.s}]$ =0.003 * {part} * fRH This formula is from page B-1 of the IWAQM Document

Where: $b_{ext.s}$ = the extinction coefficient due to particle scattering (km^{-1})
0.003 = a nominal dry scattering efficiency
{part} = the particulate concentration in ug/m3
fRH = the RH correction factor (11.5 at the assumed rh of 95%)
(the fRH is from page B-3 of the IWAQM Document)

$NH_4SO_2(b_{ext})$= $0.003 \cdot 0.55069 \cdot 11.5 = 0.01900$

$PM_{10}(b_{ext})$= $0.003 \cdot 0.07594 = 0.00023$

Total of NH_4SO_2 and PM_{10} = $0.01900 + .00023 = 0.01923$

dv = 10ln(b_{ext} / 0.01 km^{-1})

Where: dv = Deciviews
b_{ext} = the extinction coefficient (km^{-1})

dv(contribution from source)=$10 \cdot \ln\left(\frac{0.01923}{0.01}\right) = 6.5$

background extinction coefficient from IMPROVE Document page S-7 figure S.2(a)
92 Mm^{-1} = 0.092 km^{-1}

dv(background) = $10 \cdot \ln\left(\frac{0.092}{0.01}\right) = 22.2$

dv(background + source) = $10 \cdot \ln\left[\frac{(0.0920 + 0.01923)}{0.01}\right] = 24.1$

Difference of (background + source) minus Background (dv) = $24.1 - 22.2 = 1.9$