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CORPORATION

December 27, 1990

Mr. Clair Fancy
Florida Department of Environmental
Regulation
2600 Blair Stone Road
Tallahassee, Florida 32301

Dear Mr. Fancy:

Re: Application to Operate/Construct Air Pollution Sources (Six simple-cycle combustion turbine peaking units at DeBary)

Enclosed for your review and approval are five (5) copies of Florida Power Corporation's (FPC) application to operate and construct six simple-cycle combustion turbine peaking units at our DeBary facility. Also enclosed is FPC's check no. 1267700 in the amount of $5,000.00 for the application fee.

If we can provide any additional information or answer any questions regarding our application, please advise.

I will be leaving the Environmental and Licensing Department, FPC, on January 14, 1991 for a new assignment. After that date, please contact Mr. W.W. Vierday regarding this project.

Sincerely,

Judy Corces /wwv

Judy N. Corces

mrj/WWV4.Fancy.let
Encs.

GENERAL OFFICE: 3201 Thirty-fourth Street South • P.O. Box 14042 • St. Petersburg, Florida 33733 • (813) 866-5151
A Florida Progress Company

bcc: W.W. Vierday
P.A. Blizzard
E.G. Major
W.J. Pardue

File: DeBary 1992 CT Addition (Air)

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TO:
Mr. Clair Fancy
Florida Department of
Environmental Regulation
2600 Blair Stone Road
Tallahassee, Florida 32301

P.O. BOX 14042
ST. PETERSBURG, FLA. 33733

REMITTANCE ADVICE

ATE 11/30/90 VENDOR FLORIDA DEPARTMENT OF VENDOR NO. 234216 CHECK NO. 126770

ICE NO.	DATE	OUR ORDER NO.	VOUCHER	GROSS AMOUNT	DISCOUNT	NET AMOUNT
FL111950C	11/19/90 CK82537		11157821	5,000.00		5,000.00
					TOTAL	5,000.00

PLEASE DETACH BEFORE DEPOSITING

FORM 935-600

THE ATTACHED REMITTANCE IS IN FULL SETTLEMENT OF ACCOUNT AS STATED. IF NOT CORRECT PLEASE RETURN TO ABOVE ADDRESS.

Florida Power
CORPORATION

St. Petersburg, Florida
SOUTHEAST BANK, N.A.
CORPORATE BANKING DIVISION
TAMPA, FLORIDA

63-406
631

CHECK NO. 1267700

$5*THOUSAND*DOLLARS AND 00 CENTS

DATE 11/30/90

$******5,000.00

Florida Power Corporation

TO THE ORDER OF

FLORIDA DEPARTMENT OF
ENVIRONMENTAL REGULATION
2600 BLAIR STONE RD
TALLAHASSEE FL
32301

K E McDonald

⑈1267700⑈ ⑆063104066⑆ 103 516936⑈

$5,000 pd.
12-31-90
Recpt. #15123

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

AC64-191015
PSD-FL-167

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Electric Generating Station [X] New[1] [ ] Existing[1]

APPLICATION TYPE: [X] Construction [ ] Operation [ ] Modification

COMPANY NAME: Florida Power Corporation COUNTY: Volusia

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) 6 Simple Cycle Combustion Turbines

SOURCE LOCATION: Street Highlands Road City DeBary

UTM: East 467.5 km North 3197.2 km

Latitude 28 ° 54 ' 14 "N Longitude 81 ° 19 ' 59 "W

APPLICANT NAME AND TITLE: R.W. Neiser, Senior Vice President, Legal and Governmental Affairs

APPLICANT ADDRESS: 3201 34th Street South, St. Petersburg, FL 33733

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of Florida Power Corporation

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

*Attach letter of authorization

Signed: R. W. Neiser

R.W. Neiser, Senior Vice President, Legal and Governmental Affairs
Name and Title (Please Type)

Date: 12/27/90 Telephone No. (813) 866-5784

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

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

---

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

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

Signed Kennard F. Kosky

Kennard F. Kosky
Name (Please Type)

KBN Engineering and Applied Sciences, Inc.
Company Name (Please Type)

1034 N.W. 57th Street, Gainesville, FL
Mailing Address (Please Type)

Florida Registration No. 14996 Date: 12/21/90 Telephone No. (904) 331-9000

SECTION II: GENERAL PROJECT INFORMATION

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

Six simple-cycle combustion turbine, peaking units designed to burn No. 2 fuel oil. Each combustion turbine is a GE model PG7111EA, equipped with water injection for NO_x control to 42 PPMVD at 15% oxygen with fuel-bound nitrogen content less than 0.015 percent. Each unit is site-rated at 92.9 MW (at 59°F) for a total site rating of 557.4 MW.

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

Start of Construction August 1991* Completion of Construction December 1992*

*For first 4 units only.

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.)

See attached Table 4-4 in PSD application

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

A064-129252, Peaking Units No. 1 through 6;

A064-125826, Steam Boilers No. 1 and 2

E. Requested permitted equipment operating time: hrs/day 24; days/wk 7; wks/yr 52; If power plant, hrs/yr 8,760; if seasonal, describe: ______

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

1. Is this source in a non-attainment area for a particular pollutant? No
   a. If yes, has "offset" been applied? ______
   b. If yes, has "Lowest Achievable Emission Rate" been applied? ______
   c. If yes, list non-attainment pollutants. ______
2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. Yes
3. Does the State "Prevention of Significant Deterioration" (PSD) requirement apply to this source? If yes, see Sections VI and VII. Yes
4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? Yes
5. Do "National Emission Standards for Hazardous Air Pollutants" (NESHAP) apply to this source? No

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

   a. If yes, for what pollutants? ______
   b. If yes, in addition to the information required in this form, any information requested in Rule 17-2.650 must be submitted.

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

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

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

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		
Well Water	N/A	N/A		
Annual Avg.*			57 x 10^6 gallons	
Peak Daily**			1.3 x 10^6 gallons	

*Based on 6 CTG units operating 1,500 hrs/yr at base load.

**Based on 6 CTG units operating at peak load and 20F.

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

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)

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
PM	15	65.7	NA	NA	15	65.7	See
SO$_2$[5]	555	2,430.2	0.8% sulfur	888	555	2,430.2	Figure
NO$_x$[6]	182	799	92 ppmvd	399.6	182	799	2-1 in
CO	54	235.2	NA	NA	54	235.2	PSD
VOC	5	21.9	NA	NA	5	21.9	app.

See also Table A-1 through A-6; data shown based on one CT.

[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 with control (See Section V, Item 3).

[5] Potential emissions using 0.5% sulfur maximum presented; actual sulfur content of No. 2 fuel oil over last 5 years was 0.31% (see Table 4-6).

[6] Does not include allowance for fuel-bound nitrogen (FBN); if FBN exceeds 0.015%, the allowance under 40 CFR Part 60 Subpart GG is requested (see Table 4-1).

D. Control Devices: (See Section V, Item 4)

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
Gas Turbine Water		Controlled to		
Injection (GE PG7111E A)	NO_x	42 PPMDV @ 15% O_2	N/A	N/A
Quiet Combustor				

E. Fuels

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
No. 2 Distillate Oil			
+ Per CT Unit	7,178*	8,698**	1,144**
+ For 4 CT Units	28,712*	34,792**	4,576**
+ For 6 CT Units	43,068*	52,188**	6,864**

+Units: Natural Gas--MMCF/hr; Fuel Oils--gallons/hr; Coal, wood, refuse, other--lbs/hr.
*Based on CT operation at base load and 59F. **Based on CT operation at peak load and and 20F.

Fuel Analysis:

Percent Sulfur: 0.5 WT % Max Percent Ash: 0.01 WT % Max

Density: 7.09 lbs/gal Typical Percent Nitrogen: 0.03 WT%

Heat Capacity: 18,550 (LHV) BTU/lb 131,520 (LHV) BTU/gal

Other Fuel Contaminants (which may cause air pollution): None

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

Annual Average N/A Maximum N/A

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

1. Water treatment system wastewater will be neutralized before disposal to on-site percolation ponds.
2. Oily wastes will be collected in an oil/water separator, with the oil pumped out periodically for off-site disposal. Water from oil/water separator will be disposed to the on-site percolation ponds.

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

Stack Height: 50 ft. Stack Diameter: 8'-8" x 17'-4" (13.8 effective) ft.

Gas Flow Rate: 1,662,283 ACFM 594,638 DSCFM Gas Exit Temperature: 1,016 °F.

Water Vapor Content: 5.80 % Velocity: 184.4 FPS

See Tables A-1 through A-20 in PSD application

SECTION IV: INCINERATOR INFORMATION

Type of Waste	Type 0 (Plastics)	Type II (Rubbish)	Type III (Refuse)	Type IV (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)							

Description of Waste ____________________

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

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

Manufacturer ____________________

Date Constructed __________ Model No. __________

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

Stack Height: ________ ft. Stack Diameter: __________ Stack Temp. __________

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

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

Type of pollution control devices: [ ] Cyclone [ ] Wet Scrubber [ ] Afterburner [ ] Other

(specify) ____________________

Brief description of operating characteristics of control devices: ____________

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

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

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]
   Not Applicable
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods, 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made.
   See Tables A-1 through A-20 in PSD application.
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   Manufacturer data sheets and emission factors; See Tables A-1 through A-20.
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.)
   Water injection; see Tables A-1, A-6, A-11, and A-16 in 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).
   Manufacturers' guarantees form the basis of emission estimates; see Tables A-1 through A-20 in PSD application.
6. An 8 ½" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained.
   See Figure 2-1 in PSD application.
7. An 8 ½" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Examples: Copy of relevant portion of USGS topographic map).
   See Figure 1-1 in PSD application.
8. An 8 ½" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   See Figure 1-1 in PSD application.

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation.

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

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

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

[X] Yes [ ] No

Contaminant	Rate or Concentration
NO_x	92 ppmvd corrected to 15% O_2 (when corrected
	for heat rate)
SO_2	0.8% sulfur fuel

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

[X] Yes [ ] No

Contaminant	Rate or Concentration
See Section 4.0 in PSD	
application	

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

Contaminant	Rate or Concentration
See Section 4.0 in PSD application	

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

1. Control Device/System:
2. Operating Principles:
3. Efficiency:*
4. Capital Costs:

*Explain method of determining

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.

b. Diameter ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

E. Describe the control and treatment technology available (As many types as applicable, use additional pages if necessary). See Section 4.0 in PSD application.

1.

a. Control Devices:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

2.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

[1] Explain method of determining efficiency.

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

j. Applicability to manufacturing processes:

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

3.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

4.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

F. Describe the control technology selected: See Section 4.0 in PSD application.

1. Control Device:

2. Efficiency:[1]

3. Capital Cost:

4. Useful Life:

5. Operating Cost:

6. Energy:[2]

7. Maintenance Cost:

8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City:

(4) State:

---

[1] Explain method of determining efficiency.

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

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

---

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

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

See Section 5.0 in PSD application

A. Company Monitored Data

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

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

Other data recorded ________________________________

Attach all data or statistical summaries to this application.

*Specify bubbler (B) or continuous (C).

2. Instrumentation, Field and Laboratory

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

b. Was instrumentation calibrated in accordance with Department procedures?

[ ] Yes [ ] No [ ] Unknown

B. Meteorological Data Used for Air Quality Modeling
See Section 6.1 in PSD application

1. ______ Year(s) of data from ______/____/______ to ______/____/______
month day year month day year

2. Surface data obtained from (location)________________________

3. Upper air (mixing height) data obtained from (location) ________________

4. Stability wind rose (STAR) data obtained from (location) ________________

C. Computer Models Used
See Section 6.1 in PSD application

1. ________________________ Modified? If yes, attach description.

2. ________________________ Modified? If yes, attach description.

3. ________________________ Modified? If yes, attach description.

4. ________________________ Modified? If yes, attach description.

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

D. Applicants Maximum Allowable Emission Data
See Section 6.1 in PSD application

Pollutant	Emission Rate
TSP	________________ grams/sec
SO^2	________________ grams/sec

E. Emission Data Used in Modeling
See Section 6.1 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 Section 4.0 in PSD application

H. Attach scientific, engineering, and technical material, reports, publications, journals, and other competent relevant information describing the theory and application of the requested best available control technology.
See Section 4.0 in PSD application

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION FOR THE PROPOSED SIMPLE CYCLE COMBUSTION TURBINES FPC DEBARY FACILITY

Prepared For:

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

Prepared By:

KBN Engineering and Applied Sciences, Inc.
1034 NW 57th Street
Gainesville, Florida 32605

November 1990
90095B1

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ACRONYMS AND ABBREVIATIONS

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AAQS	Ambient Air Quality Standards
ABB	Asea Brown Boveri
acfm	actual cubic feet per minute
As	arsenic
BACT	best available control technology
Be	beryllium
10^6 Btu/hr	million British thermal units per hour
Btu/kWh	British thermal units per kilowatt hour
CAA	Clean Air Act
CFR	Code of Federal Regulations
CO	carbon monoxide
CT	combustion turbine
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
°F	degrees Fahrenheit
F.A.C.	Florida Administrative Code
FBN	fuel-bound nitrogen
FDER	Florida Department of Environmental Regulation
FGD	flue gas desulfurization
FPC	Florida Power Corporation
FPL	Florida Power & Light Company
ft	foot/feet
GEP	good engineering practice
gr/scf	grains per standard cubic feet
H_2SO_4	sulfuric acid
Hg	mercury
HRSG	heat recovery steam generators
HSH	highest, second highest
ISC	Industrial Source Complex
ISCST	Industrial Source Complex Short-Term
ISO	International Organization for Standardization
KBN	KBN Engineering and Applied Sciences, Inc.
km	kilometer
LAER	lowest achievable emission rate
lb/hr	pounds per hour
m	meter
MW/hr	megawatts per hour
MW	monitor well
NH_3	ammonia
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSCR	nonselective catalytic reduction
NSPS	New Source Performance Standards
NWS	National Weather Service
PM(TSP)	total suspended particulate matter
PM10	particulate matter less than or equal to 10 micrometers
ppm	parts per million
ppmvd	parts per million volume, dry
PSD	prevention of significant deterioration

ACRONYMS AND ABBREVIATIONS
(Page 2 of 2)

SCR	selective catalytic reduction
SIP	Site Implementation Plan
SNCR	selective noncatalytic reduction
SO_2	sulfuric dioxide
SO_3	sulfuric trioxide
TPH	tons per hour
TPY	tons per year
UNAMAP	Users Network for Applied Modeling of Air Pollution
VOC	volatile organic compound

1.0 INTRODUCTION

Florida Power Corporation (FPC) is proposing to locate up to 557.4 megawatts (MW) of simple cycle combustion turbines (CTs) at the existing DeBary facility. The DeBary Plant site is located in Volusia County about 1 mile northwest of DeBary (Figure 1-1). Each simple cycle CT will have a peak load of 92.9 MW at an ambient temperature of 59 degrees Fahrenheit (°F) and a generating capacity of 76 to 105 MW, depending upon ambient temperature and operating conditions. The six CTs needed to generate up to 557.4 MW will be located adjacent to six existing CTs which have a generating capacity of 282 MW (Figure 1-2).

KBN Engineering and Applied Sciences, Inc. (KBN) has been contracted by FPC to provide air permitting services for the DeBary expansion. Initially, preliminary analyses were performed to determine compliance with prevention of significant deterioration (PSD) increments and preconstruction _de minimis_ monitoring levels for the proposed plant only. A full PSD review was then performed to determine whether significant air quality deterioration will result from the proposed facility and other PSD increment consuming sources and to determine compliance with ambient air quality standards (AAQS). The PSD review included control technology review, source impact analysis, air quality analysis (monitoring), and additional impact analyses.

The existing DeBary plant is considered to be an existing major facility because emissions of regulated pollutants exceed 250 tons per year (TPY). PSD review is required for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates which would constitute a major modification. The potential emissions from the proposed project will exceed the PSD significant emission rates for the following regulated pollutants: sulfur dioxide (SO_2), particulate matter as total suspended particulate [PM(TSP)], particulate matter with an aerodynamic diameter less than or equal to 10 micrometers (PM10), nitrogen dioxide (NO_2), carbon monoxide (CO), sulfuric acid (H_2SO_4) mist, beryllium (Be), mercury (Hg),

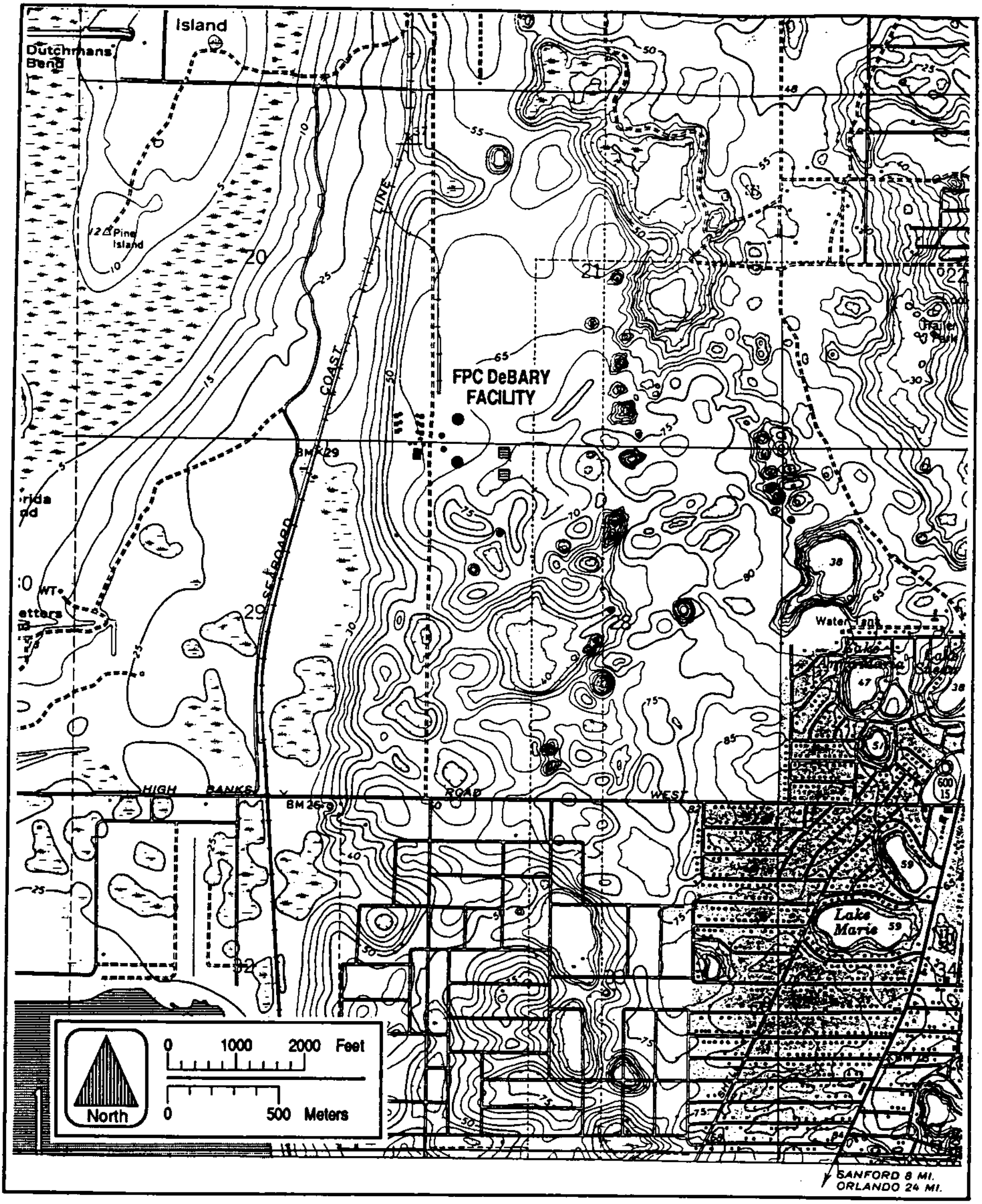

Figure 1-1 LOCATION OF THE FPC DeBARY FACILITY

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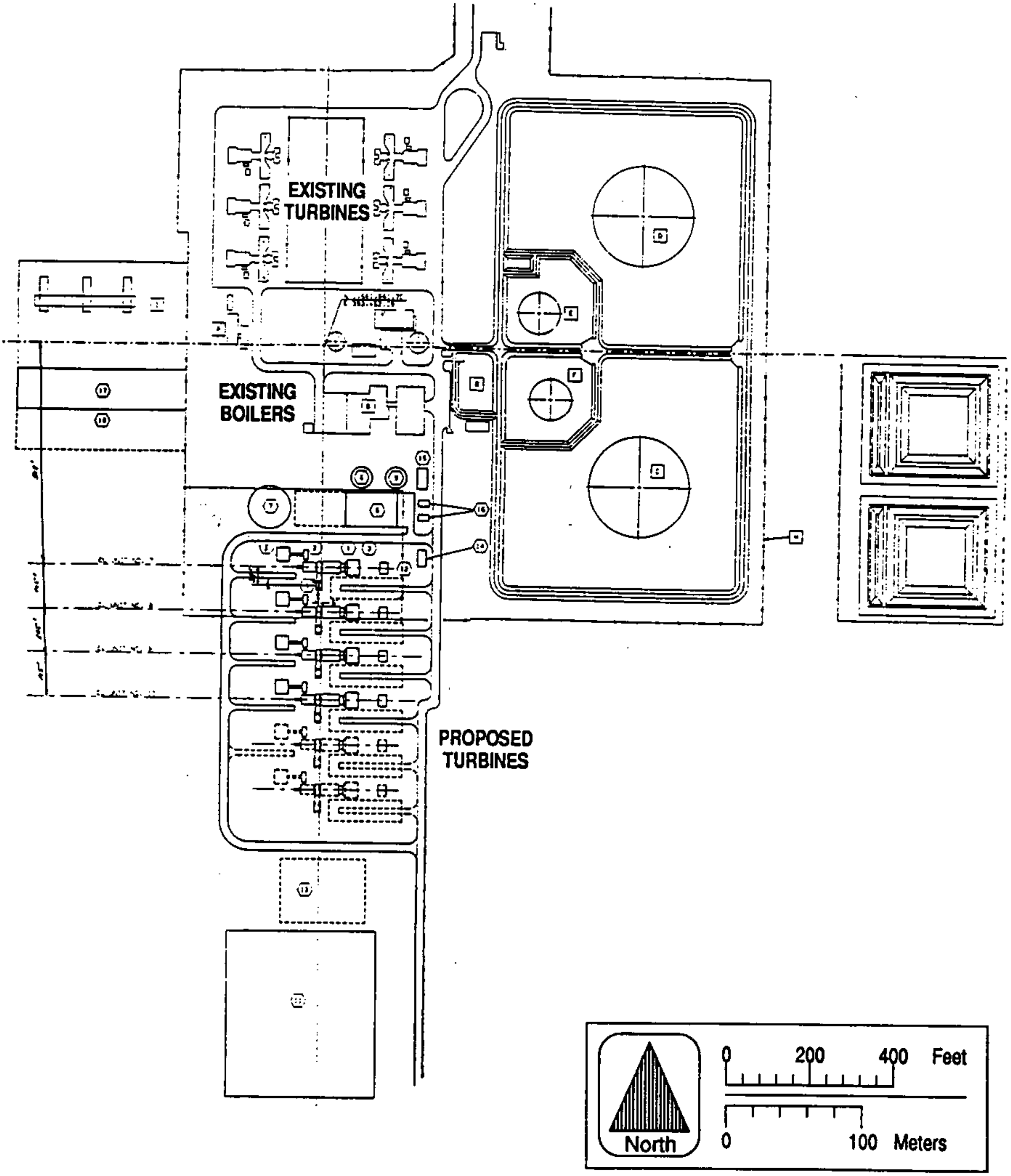

Figure 1-2 SITE PLAN OF THE EXISTING TURBINE AND BOILERS AND PROPOSED TURBINES

KBN

and arsenic (As). Therefore, the project is subject to PSD review for these pollutants.

This report is presented in eight sections. Descriptions of the existing operation and proposed project are given in Section 2.0. The air quality review requirements and applicability of the project to the PSD and nonattainment regulations are presented in Section 3.0. The control technology review for the CTs applicable under the U.S. Environmental Protection Agency's (EPA's) current top-down approach is discussed in Section 4.0. The air quality monitoring data, including the use of existing air quality monitoring data to satisfy the PSD preconstruction monitoring requirements, are given in Section 5.0. The air source impact analysis approach is presented in Section 6.0. The results of the air quality analyses are summarized in Section 7.0. Additional impact analyses associated with the project's impacts on vegetation, soils, and associated growth are discussed in Section 8.0.

2.0 EXISTING OPERATION AND PROJECT DESCRIPTION

2.1 EXISTING OPERATION

The existing facility consists of six peaking gas turbine units and two boilers. Each of the six gas turbines has a maximum permitted heat input rate of 588 million British thermal units per hour (10^6 Btu/hr) at 95°F with a 47 megawatts per hour (MW/hr) output and is fired with No. 2 or No. 6 fuel oil. The two boilers operate at a maximum heat input rate of 26 x 10^6 Btu/hr while burning either No. 2 fuel oil or No. 6 fuel oil only and each is used to heat No. 6 fuel oil for the peaking gas turbines. The maximum sulfur content in the fuel oil fired in the turbines and boilers is 0.7 percent. The combustion unit descriptions and emission factors for these sources are presented in Table 2-1. The stack, operating, and emission data for these sources are given in Table 2-2.

2.2 PROJECT DESCRIPTION

The proposed project will consist of six simple-cycle CT peaking units designed to burn No. 2 distillate fuel oil and natural gas. The DeBary site currently does not have natural gas firing capability. However, the new CTs can be modified to burn natural gas so that future gas capability can be accommodated. The operating and emission data for oil firing were used to assess impacts and evaluate best available control technology (BACT) because emissions with this fuel are higher than those for natural gas and distillate oil is currently planned as the primary fuel.

Each CT is site-rated at 92.9 MW at 59°F for a total site rating of 557.4 MW (see Figure 2-1). Design information and operating parameters for an individual CT when firing distillate oil at ambient temperatures of 20, 59, and 90°F are presented in Appendix A. Information is also provided for the CTs operating at 100, 75, 50, and 25 percent load.

The maximum emissions from the CTs occur at the lowest design temperature of 20°F, while the lowest exit gas flow rates occur at the highest design

Table 2-1. Combustion Unit Descriptions and Emission Factors for Existing Sources at FPC's DeBary Facility

Unit	Fuel	Heat Input Rate (10^6 Btu/hr)	Maximum Fuel Use	Emission Factors					
				Units	PM	SO_2	NO_2	CO	VOC
Boilers No. 1 and No. 2	No. 6 oil	26.0	179 gal/hr	lb/10^6 Btu	0.021[a]	0.75[a]	0.344[a]	0.028[a]	0.010[a]
Gas Turbines No. 1 through No. 6	No. 6 oil	588.0	4,055 gal/hr	lb/10^6 Btu lb/10^3 gal	0.034 5	0.68 98[b]	0.47 67.8	0.11 15.4	0.04 5.57

Note: Heat contents for No. 6 fuel oil is assumed to be approximately 145,000 Btu/gal.

Btu = British thermal units.
Btu/gal = British thermal units per gallon.
CO = carbon monoxide.
gal/hr = gallons per hour.
lb/10^6 Btu = pounds per million British thermal units.
lb/10^3 gal = pounds per thousand gallons.
NO_2 = nitrogen dioxide.
PM = particulate matter.
SO_2 = sulfur dioxide.
VOC = volatile organic compound.

[a] Based on permit condition. For boilers, maximum sulfur content in fuel oil is limited to 0.7 percent.
[b] Based on emission factor of 140 x S, where S is the sulfur content, assumed to be 0.7 percent.

Table 2-3. Design, Stack, Operating, and Emission Data for the Proposed Combustion Turbines Operating at Various Loads

Parameter	Operating Load for Each Turbine			
	100[a]	75	50	25
Heat Input, 10^6 Btu/hr[b]	1,144.3	806.4	593.1	399.7
Stack Height, ft (m)	50 (15.2)	50 (15.2)	50 (15.2)	50 (15.2)
Stack Diameter, ft (m)	13.8 (4.22)	13.8 (4.22)	13.8 (4.22)	13.8 (4.22)
Stack Gas Velocity ft/sec (m/sec)[c]	161.5 (49.2)	135.4 (41.3)	112.4 (34.3)	95.5 (29.1)
Stack Gas Exit Temperature °F (K)[c]	1,065 (847)	843 (724)	761 (678)	660 (622)
SO_2 Emission Rate, lb/hr (g/s) Each Turbine[c]	616.9 (77.7)	434.7 (54.8)	319.8 (40.3)	215.5 (27.1)

Note: The stacks were located at the relative x,y (m) values of: 0.0, 79.7; 0.0, 46.9; 0.0, 16.4; 0.0, -16.4; 0.0, -46.9; and 0.0, -79.7.

[a] Peak load.
[b] Operating data at ambient temperature of 20°F.
[c] Operating data at ambient temperature of 90°F.

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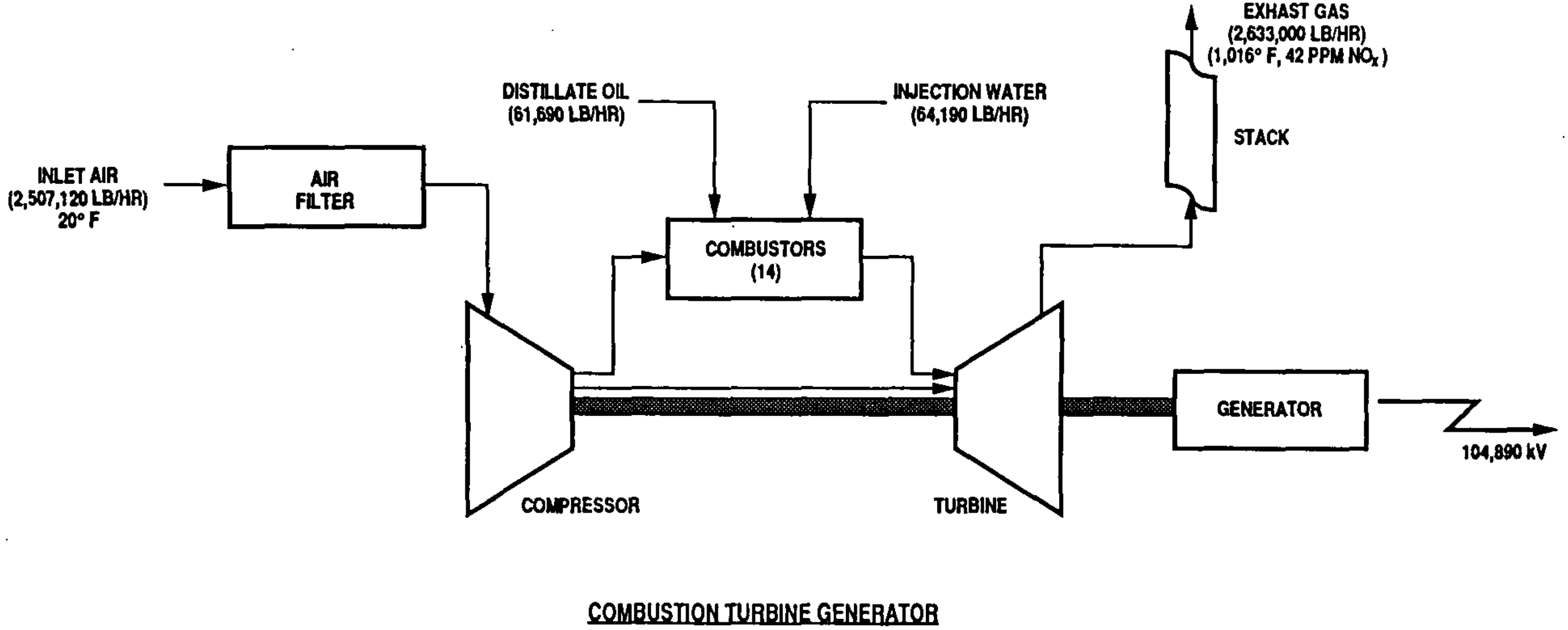

Figure 2-1 COMBUSTION TURBINE FLOW DIAGRAM
PEAK LOAD OPERATION (100%) AT 20° F AMBIENT

temperature of 95°F. In order to provide a conservative estimate of impacts (i.e., higher than expected), modeling was performed using the highest emissions at the 20°F design condition coupled with the lowest exit gas flow rates at 95°F design condition. The stack, operating, and SO_2 emission data for four operating loads are given in Table 2-3.

Table 2-3. Design, Stack, Operating, and Emission Data for the Proposed Combustion Turbines Operating at Various Loads

Parameter	Operating Load for Each Turbine			
	100[a]	75	50	25
Boiler Heat Input, 10^6 Btu/hr[b]	1,144.3	806.4	593.1	399.7
Stack Height, ft (m)	50 (15.2)	50 (15.2)	50 (15.2)	50 (15.2)
Stack Diameter, ft (m)	13.8 (4.22)	13.8 (4.22)	13.8 (4.22)	13.8 (4.22)
Stack Gas Velocity ft/sec (m/sec)[c]	161.5 (49.2)	135.4 (41.3)	112.4 (34.3)	95.5 (29.1)
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Note: The stacks were located at the relative x,y (m) values of: 0.0, 79.7; 0.0, 46.9; 0.0, 16.4; 0.0, -16.4; 0.0, -46.9; and 0.0, -79.7.

[a] Peak load.
[b] Operating data at ambient temperature of 20°F.
[c] Operating data at ambient temperature of 90°F.

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 DeBary project. These regulations must be satisfied before the proposed simple-cycle turbines can begin operation.

3.1 NATIONAL AND STATE AAQS

The existing applicable national and Florida AAQS are presented in Table 3-1. Primary national AAQS were promulgated to protect the public health, and secondary national AAQS were promulgated to protect the public welfare from any known or anticipated adverse effects associated with the presence of pollutants in the ambient air. Areas of the country in violation of AAQS are designated as nonattainment areas, and new sources to be located in or near these areas may be subject to more stringent air permitting requirements.

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a preconstruction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA, and therefore PSD approval authority has been granted to the Florida Department of Environmental Regulation (FDER).

A "major facility" is defined as any one of 28 named source categories which has the potential to emit 100 TPY or more, or any other stationary facility which has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significance Levels ($\mu g/m^3$)

		AAQS					
		National		State of Florida	PSD Increments		Significant Impact Levels
Pollutant	Averaging Time	Primary Standard	Secondary Standard		Class I	Class II	
Particulate Matter (TSP)	Annual Geometric Mean	NA	NA	NA	5	19	1
	24-Hour Maximum[a]	NA	NA	NA	10	37	5
Particulate Matter (PM10)	Annual Arithmetic Mean	50	50	50	4[c]	17[c]	1
	24-Hour Maximum[b]	150	150	150	8[c]	30[c]	5
Sulfur Dioxide	Annual Arithmetic Mean	80	NA	60	2	20	1
	24-Hour Maximum[b]	365	NA	260	5	91	5
	3-Hour Maximum[b]	NA	1,300	1,300	25	512	25
Carbon Monoxide	8-Hour Maximum[b]	10,000	10,000	10,000	NA	NA	500
	1-Hour Maximum[b]	40,000	40,000	40,000	NA	NA	2,000
Nitrogen Dioxide	Annual Arithmetic Mean	100	100	100	2.5	25	1
Ozone	1-Hour Maximum[d]	235	235	235	NA	NA	NA
Lead	Calendar Quarter Arithmetic Mean	1.5	1.5	15	NA	NA	NA

[a] Maximum concentration not to be exceeded more than once per year.
[b] Achieved when the expected number of exceedances per year is less than 1.
[c] Proposed October 5, 1989.
[d] Achieved when the expected number of days per year with concentrations above the standard is less than 1.

Note: Particulate matter (TSP) = total suspended particulate matter.
Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.

NA = Not applicable, i.e., no standard exists.

Sources: Federal Register, Vol. 43, No. 118, June 19, 1978.
40 CFR 50.
40 CFR 52.21.
Chapter 17-2.400, F.A.C.

A "major modification" is defined under PSD regulations as a change at an existing major facility which increases emissions by greater than significant amounts. PSD significant emission rates are shown in Table 3-2.

PSD review is used to determine whether significant air quality deterioration will result from the new or modified facility. Federal PSD requirements are contained in 40 CFR 52.21, Prevention of Significant Deterioration of Air Quality. The State of Florida has adopted PSD regulations that are essentially identical to federal regulations [Chapter 17-2.510, Florida Administrative Code (F.A.C.)]. Major facilities and major modifications are required to undergo the following analysis related to PSD for each pollutant emitted in significant amounts:

1. Control technology review,
2. Source impact analysis,
3. Air quality analysis (monitoring),
4. Source information, and
5. Additional impact analyses.

In addition to these analyses, a new facility must also be reviewed with respect to Good Engineering Practice (GEP) stack height regulations. Discussions concerning each of these requirements are presented in the following sections.

3.2.2 INCREMENTS/CLASSIFICATIONS

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality baseline concentration level of SO_2 and PM(TSP) concentrations would constitute significant deterioration. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications were designated based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks, national wilderness areas, and memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres)

Table 3-2. PSD Significant Emission Rates and <u>De Minimis</u> Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	<u>De Minimis</u> Monitoring Concentration ($\mu g/m^3$)
Sulfur Dioxide	NAAQS, NSPS	40	13, 24-hour
Particulate Matter (TSP)	NAAQS, NSPS	25	10, 24-hour
Particulate Matter (PM10)	NAAQS	15	10, 24-hour
Nitrogen Oxides	NAAQS, NSPS	40	14, annual
Carbon Monoxide	NAAQS, NSPS	100	575, 8-hour
Volatile Organic Compounds (Ozone)	NAAQS, NSPS	40	100 TPY[a]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Asbestos	NESHAP	0.007	NM
Beryllium	NESHAP	0.0004	0.001, 24-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Vinyl Chloride	NESHAP	1	15, 24-hour
Benzene	NESHAP	b	NM
Radionuclides	NESHAP	b	NM
Inorganic Arsenic	NESHAP	b	NM

Note: Ambient monitoring requirements for any pollutant may be exempted if the impact of the increase in emissions is below <u>de minimis</u> monitoring concentrations.

NAAQS = National Ambient Air Quality Standards.
NM = No ambient measurement method.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
$\mu g/m^3$ = micrograms per cubic meter.

[a] No <u>de minimis</u> concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.
[b] Any emission rate of these pollutants.

Sources: 40 CFR 52.21.
Chapter 17-2, F.A.C.

or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. EPA then promulgated as regulations the requirements for classifications and area designations.

On October 17, 1988, EPA promulgated regulations to prevent significant deterioration due to emissions of nitrogen oxides (NO_x) and established PSD increments for NO_2 concentrations. The EPA class designations and allowable PSD increments are presented in Table 3-1. FDER has adopted the EPA class designations and allowable PSD increments for SO_2, PM(TSP), and NO_2 increments.

The term "baseline concentration" evolves from federal and state PSD regulations and refers to a concentration level corresponding to a specified baseline date and certain additional baseline sources. By definition, in the PSD regulations as amended August 7, 1980, baseline concentration means the ambient concentration level that exists in the baseline area at the time of the applicable baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and includes:

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

The following emissions are not included in the baseline concentration and therefore affect PSD increment consumption:

1. Actual emissions from any major stationary facility on which construction commenced after January 6, 1975, for SO_2 and PM(TSP) concentrations, and after February 8, 1988, for NO_2 concentrations; and

2. Actual emission increases and decreases at any stationary facility occurring after the baseline date.

In reference to the baseline concentration, the term "baseline date" actually includes three different dates:

1. The major facility baseline date, which is January 6, 1975, in the cases of SO_2 and PM(TSP), and February 8, 1988, in the case of NO_2.
2. The minor facility baseline date, which is the earliest date after the trigger date on which a major stationary facility or major modification subject to PSD regulations submits a complete PSD application.
3. The trigger date, which is August 7, 1977, for SO_2 and PM(TSP), and February 8, 1988, for NO_2.

The minor source baseline date for SO_2 and PM(TSP) has been set as December 27, 1977, for the entire State of Florida (Chapter 17-2.450, F.A.C.).

3.2.3 CONTROL TECHNOLOGY REVIEW

The control technology review requirements of the federal and state PSD regulations require that all applicable federal and state emission limiting standards be met and that BACT be applied to control emissions from the source [Chapter 17-2.500(5)(c), F.A.C]. The BACT requirements are applicable to all regulated pollutants for which the increase in emissions from the facility or modification exceeds the significant emission rate (see Table 3-2).

BACT is defined in Chapter 17-2.100(25), F.A.C., as:

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

> economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation.

The requirements for BACT were promulgated within the framework of PSD in the 1977 amendments of the CAA [Public Law 95-95; Part C, Section 165(a)(4)]. The primary purpose of BACT is to optimize consumption of PSD air quality increments and thereby enlarge the potential for future economic growth without significantly degrading air quality (EPA, 1978; 1980). Guidelines for the evaluation of BACT can be found in EPA's Guidelines for Determining Best Available Control Technology (BACT), (EPA, 1978) and in the PSD Workshop Manual (EPA, 1980). These guidelines were promulgated by EPA to provide a consistent approach to BACT and to ensure that the impacts of alternative emission control systems are measured by the same set of parameters. In addition, through implementation of these guidelines, BACT in one area may not be identical to BACT in another area. According to EPA (1980), "BACT analyses for the same types of emissions unit and the same pollutants in different locations or situations may determine that different control strategies should be applied to the different sites, depending on site-specific factors. Therefore, BACT analyses must be conducted on a case-by-case basis."

The BACT requirements are intended to ensure that the control systems incorporated in the design of a proposed facility reflect the latest in control technologies used in a particular industry and take into consideration existing and future air quality in the vicinity of the proposed facility. BACT must, as a minimum, demonstrate compliance with New Source Performance Standards (NSPS) for a source (if applicable). An evaluation of the air pollution control techniques and systems, including a cost-benefit analysis of alternative control technologies capable of achieving a higher degree of emission reduction than the proposed control technology, is required. The cost-benefit analysis requires the documentation of the materials, energy, and economic penalties associated with the proposed and alternative control systems, as well as the environmental benefits derived from these systems. A decision on BACT is to be based on sound judgment, balancing environmental benefits with energy, economic, and other impacts (EPA, 1978).

Historically, a "bottom-up" approach consistent with the BACT Guidelines and PSD Workshop Manual has been used. With this approach, an initial control level, which is usually NSPS, is evaluated against successively more stringent controls until a BACT level is selected. However, EPA developed a concern that the bottom-up approach was not providing the level of BACT decisions originally intended. As a result, in December 1987, the EPA Assistant Administrator for Air and Radiation mandated changes in the implementation of the PSD program including the adoption of a new "top-down" approach to BACT decision making.

The top-down BACT approach essentially starts with the most stringent (or top) technology and emissions limit that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between the proposed facility and the facility on which the control technique was applied previously must be justified. Recently, EPA issued a draft guidance document on the top-down approach entitled Top-Down Best Available Control Technology Guidance Document (EPA, 1990).

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

In accordance with requirements of 40 Code of Federal Regulations (CFR) 52.21(m) and Chapter 17-2.500(f), F.A.C, any application for a PSD permit must contain an analysis of continuous ambient air quality data in the area affected by the proposed major stationary facility or major modification. For a new major facility, the affected pollutants are those that the facility potentially would emit in significant amounts. For a major modification, the pollutants are those for which the net emissions increase exceeds the significant emission rate (see Table 3-2).

Ambient air monitoring for a period of up to 1 year is generally appropriate to satisfy the PSD monitoring requirements. A minimum of 4 months of data is required. Existing data from the vicinity of the proposed source may be utilized if the data meet certain quality assurance requirements; otherwise, additional data may need to be gathered. Guidance in designing a PSD monitoring network is provided in EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration (EPA, 1987a).

The regulations include an exemption which excludes or limits the pollutants for which an air quality analysis must be conducted. This exemption states that FDER may exempt a proposed major stationary facility or major modification from the monitoring requirements with respect to a particular pollutant if the emissions increase of the pollutant from the facility or modification would cause, in any area, air quality impacts less than the de minimis levels presented in Table 3-2 [Chapter 17-2.500(3)(e), F.A.C.].

3.2.5 SOURCE IMPACT ANALYSIS

A source impact analysis must be performed for a proposed major source subject to PSD for each pollutant for which the increase in emissions exceeds the significant emission rate (Table 3-2). The PSD regulations specifically provide for the use of atmospheric dispersion models in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with AAQS and allowable PSD increments. Designated EPA models normally must be used in performing the impact analysis. Specific applications for other than EPA-approved models require EPA's consultation and prior approval. Guidance for the use and application of dispersion models is presented in the EPA publication Guideline on Air Quality Models (Revised) (EPA, 1987b). The source impact analysis for criteria pollutants may be limited to only the new or modified source if the net increase in impacts due to the new or modified source is below significance levels, as presented in Table 3-1.

Various lengths of record for meteorological data can be utilized for impact analysis. A 5-year period can be used with corresponding evaluation of highest, second-highest short-term concentrations for comparison to AAQS or PSD increments. The term "highest, second-highest" (HSH) refers to the highest of the second-highest concentrations at all receptors (i.e., the highest concentration at each receptor is discarded). The second-highest concentration is significant because short-term AAQS specify that the standard should not be exceeded at any location more than once a year. If less than 5 years of meteorological data are used in the modeling analysis, the highest concentration at each receptor normally must be used for comparison to air quality standards.

3.2.6 ADDITIONAL IMPACT ANALYSIS

In addition to air quality impact analyses, federal and State of Florida PSD regulations require analyses of the impairment to visibility and the impacts on soils and vegetation that would occur as a result of the proposed source [40 CFR 52.21; Chapter 17-2.500(5)(e), F.A.C.]. These analyses are to be conducted primarily for PSD Class I areas. Impacts due to general commercial, residential, industrial, and other growth associated with the source must also be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

3.2.7 GOOD ENGINEERING PRACTICE STACK HEIGHT

The 1977 CAA Amendments require that the degree of emission limitation required for control of any pollutant not be affected by a stack height that exceeds GEP or any other dispersion technique. On July 8, 1985, EPA promulgated final stack height regulations (EPA, 1985a). Identical regulations have been adopted by FDER [Chapter 17-2.270, F.A.C.]. GEP stack height is defined as the highest of:

1. 65 meters (m), or
2. A height established by applying the formula:

$$Hg = H + 1.5L$$

where: Hg = GEP stack height,
H = Height of the structure or nearby structure, and
L = Lesser dimension (height or projected width) of nearby structure(s), or

3. A height demonstrated by a fluid model or field study.

"Nearby" is defined as a distance up to five times the lesser of the height or width dimensions of a structure or terrain feature, but not greater than 0.8 kilometers (km). Although GEP stack height regulations require that the stack height used in modeling for determining compliance with AAQS and PSD increments not exceed the GEP stack height, the actual stack height may be greater.

The stack height regulations also allow increased GEP stack height beyond that resulting from the above formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or predicted to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain which exceeds the height calculated by the GEP stack height formula.

3.3 NONATTAINMENT RULES

Based on the current nonattainment provisions (Chapter 17-2.510, F.A.C.), all major new facilities and modifications to existing major facilities located in a nonattainment area must undergo nonattainment review. A new major facility is required to undergo this review if the proposed pieces of equipment have the potential to emit 100 TPY or more of the nonattainment pollutant. A major modification at a major facility is required to undergo review if it results in a significant net emission increase of 40 TPY or more of the nonattainment pollutant or the modification is major (i.e., 100 TPY or more).

For major facilities or major modifications that locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The area of influence is defined as an area which is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on Chapter 17-2.510(2)(a)2.a, F.A.C., all volatile organic compound (VOC) sources that are located within an area of influence are exempt from the provisions of new source review for nonattainment areas. Sources that emit other nonattainment pollutants and are located within the area of influence are subject to nonattainment review unless the maximum allowable emissions from the proposed source do not have a significant impact within the nonattainment area.

3.4 SOURCE APPLICABILITY

3.4.1 AREA CLASSIFICATION

The DeBary Plant is located in Volusia County, which has been designated by EPA and FDER as an attainment area for all criteria pollutants. Volusia County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TSP), and NO_x. The DeBary site is located more than 100 km from any PSD Class I area. The nearest Class I areas to the site are the Everglades National Park and Chassahowitzka National Wildlife Refuge, which are approximately 340 km and 120 km, respectively, from the plant site.

3.4.2 PSD REVIEW

3.4.2.1 Pollutant Applicability

The existing DeBary Plant is considered to be an existing major facility because emissions of regulated pollutants exceed 250 TPY (refer to Table 2-2); therefore, PSD review is required for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates presented in Table 3-2 (i.e., major modification). As shown, potential emissions from the proposed project will exceed the PSD significant emission rates for the following regulated pollutants: SO_2, PM(TSP), PM10, NO_x, CO, H_2SO_4 mist, Be, Hg, and inorganic As. Therefore, the project is subject to PSD review for these pollutants.

3.4.2.2 Ambient Monitoring

Based upon the net increase in emissions from the proposed project, presented in Table 3-3, a PSD preconstruction ambient monitoring analysis is required for SO_2, PM(TSP), PM10, NO_x, CO, sulfuric acid mist, Be, Hg, and As. However, if the net increase in impact of a pollutant is less than the de minimis monitoring concentration, then an exemption from the preconstruction ambient monitoring requirement may be granted for that pollutant. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

If preconstruction monitoring data are required to be submitted, data collected at or near the project site can be submitted based on existing air quality data (e.g., FDER) or the collection of on-site data.

Maximum predicted impacts due to the net increase associated with the proposed project are presented in Table 3-4 for pollutants requiring PSD review. The methodology used to predict maximum impacts and the impact analysis results are presented in Sections 6.0 and 7.0. As shown in Table 3-4, the maximum net increase in impact is below the respective de minimis monitoring concentration for all pollutants. There is no

Table 3-3. Net Increase in Emissions Due to the DeBary Project Compared to the PSD Significant Emission Rates

	Emissions (TPY)		
Pollutant	Potential Emissions From Proposed Turbines	Significant Emission Rate	PSD Review
Sulfur Dioxide	14,581[a]	40	Yes
Particulate Matter (TSP)	394	25	Yes
Particulate Matter (PM10)	394	15	Yes
Nitrogen Dioxide	4,794	40	Yes
Carbon Monoxide	1,411	100	Yes
Volatile Organic Compounds	131	NA	No
Lead	0.24	0.6	No
Sulfuric Acid Mist	1,816	7	Yes
Total Fluorides	0.88	3	No
Total Reduced Sulfur[b]	NEG	10	No
Reduced Sulfur Compounds[b]	NEG	10	No
Hydrogen Sulfide[b]	NEG	10	No
Asbestos[b]	NEG	0.007	No
Beryllium	0.068	0.0004	Yes
Mercury	0.081	0.1	No
Vinyl Chloride[b]	NEG	1	No
Benzene[b]	NEG	0	No
Radionuclides[b]	NEG	0	No
Inorganic Arsenic	0.11	0	Yes

Note: NEG = Negligible.
All calculations based on 59°F peak load condition.

[a] Based on maximum sulfur content specification of 0.5 percent in fuel oil.
[b] Emissions of these pollutants considered not to have any emission rate increase.

Table 3-4. Predicted Net Increase In Impacts Due to the DeBary Project Compared to PSD <u>De Minimis</u> Monitoring Concentrations

	Concentration ($\mu g/m^3$)	
Pollutant	Predicted Net Increase In Impacts[a]	<u>De Minimis</u> Monitoring Concentration
Sulfur Dioxide	11.4	13, 24-hour
Particulate Matter (TSP)	1.2	10, 24-hour
Particulate Matter (PM10)	1.2	10, 24-hour
Nitrogen Dioxide	0.31[b]	14, annual
Carbon Monoxide	2.9	575, 8-hour
Beryllium	0.000053	0.001, 24-hour
Mercury	0.000063	0.25, 24-hour
Sulfuric Acid Mist	NA	NM
Inorganic Arsenic	NA	NM

Note: NA - Not applicable.
NM - No acceptable ambient measurement method has been developed and, therefore, <u>de minimis</u> levels have not been established by EPA.

[a] Based on maximum emissions at 100-percent load and 100-percent capacity factor.

[b] If fuel-bound nitrogen content was 0.25 percent (i.e., NO_x emission rate of 92 ppm) the maximum annual concentration is predicted to be 0.68 $\mu g/m^3$.

acceptable ambient monitoring method for sulfuric acid mist and As; therefore, monitoring is not required for these pollutants.

In May 1990, FPC submitted a preliminary air quality impact assessment of the proposed simple-cycle CTs to FDER in response to the potential SO_2 monitoring requirement. The assessment described the maximum predicted impacts due to the turbines and recommended the use of existing FDER air quality monitoring data that would be appropriate to satisfy PSD preconstruction monitoring requirements. In July 1990, FDER determined that data collected at the recommended monitoring site was acceptable for satisfying this requirement (see Appendix B).

3.4.2.3 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m high. The proposed stacks for the proposed turbines will be 50 feet (ft) in height (15.2 m) and, therefore, do not exceed the GEP stack height. The potential for downwash of the units' emissions due to nearby structures is discussed in Section 6.0, Air Quality Modeling Approach.

3.4.3 NONATTAINMENT REVIEW

The DeBary plant is located in Volusia County, which is classified as an attainment area for all criteria pollutants. The plant is also located more than 50 km from any nonattainment area. Therefore, nonattainment requirements are not applicable.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The control technology review requirements of the PSD regulations are applicable to emissions of SO_2, PM(TSP), PM10, NO_x, CO, H_2SO_4 mist, Be, Hg, and inorganic As (see Section 3.0). This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to BACT analyses is based on the regulatory definitions of BACT, as well as EPA's current policy guidance requiring the top-down approach.

4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for gas turbines are codified in 40 CFR 60, Subpart GG. These regulations apply to:

1. "Electric utility stationary gas turbines" with a heat input at peak load of greater than 100 x 10^6 Btu/hr [40 CFR 60.332 (b)];
2. "Stationary gas turbines" with a heat input at peak load between 10 and 100 x 10^6 Btu/hr [40 CFR 60.332 (c)]; or
3. "Stationary gas turbines" with a manufacturer's rate base load at ISO conditions of 30 MW or less [40 CFR 60.332 (d)].

The electric utility stationary gas turbine provisions apply to stationary gas turbines constructed for the purpose of supplying more than one-third of its potential electric output capacity to any utility power distribution system for sale [40 CFR 60.331 (q)]. The requirements for electric utility stationary gas turbines are applicable to the project and are the most stringent provision of the NSPS. These requirements are summarized in Table 4-1 and were considered in the BACT analysis.

As noted from Table 4-1, the NSPS NO_x emission limit can be adjusted upward to allow for fuel-bound nitrogen. For a fuel-bound nitrogen concentration of 0.015 percent or less, no increase in the NSPS is provided; for a fuel-bound nitrogen concentration of 0.06 percent, the NSPS is increased by 0.0024 percent or 24 parts per million (ppm).

Table 4-1. Federal NSPS For Electric Utility Stationary Gas Turbines

Pollutant	Emission Limitation[a]
Sulfur Dioxide	Maximum of 0.015 percent by volume at 15 percent oxygen on a dry basis <u>or</u> sulfur in fuel no greater than 0.8 percent by weight
Nitrogen Oxides[b]	0.0075 percent by volume (75 ppm) at 15 percent O_2 on a dry basis adjusted for heat rate and fuel nitrogen

[a] Applicable to electric utility gas turbines with a heat input at peak load of greater than 100 x 10^6 Btu/hr.

[b] Standard is multiplied by 14.4/Y; where Y is the manufacturer's rated heat rate in kilojoules per watt at rated load or actual measured heat rate based on the lower heating value of fuel measured at actual peak load; Y cannot be greater than 14.4. Standard is adjusted upward (additive) by the percent of nitrogen in the fuel:

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

where:

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

Source: 40 CFR 60 Subpart GG.

For the DeBary CTs, the NSPS emission limit would be 92 ppm corrected to 15 percent oxygen at a fuel-bound nitrogen content of 0.015 percent.

4.3 BEST AVAILABLE CONTROL TECHNOLOGY

4.3.1 NITROGEN OXIDES

4.3.1.1 Identification of NO_x Control Technologies for CTs

NO_x emissions from combustion of fossil fuels consist of thermal NO_x and fuel-bound NO_x. Thermal NO_x is formed from the reaction of oxygen and nitrogen in the combustion air at combustion temperatures. Formation of thermal NO_x depends on the flame temperature, residence time, combustion pressure, and air-to-fuel ratios in the primary combustion zone. The design and operation of the combustion chamber dictates these conditions. Fuel-bound NO_x is created by the oxidation of volatilized nitrogen in the fuel. Nitrogen content in the fuel is the primary factor in its formation.

Table 4-2 presents a listing of the lowest achievable emission rates/best available control technology (LAER/BACT) decisions for gas turbines made by state environmental agencies and EPA regional offices. This table was developed from the information contained in the LAER/BACT clearinghouse documents (EPA, 1985b, 1986, 1987c, 1988c, 1989) and by contacting state agencies, such as the California Air Control Board, the South Coast Air Quality Management District, the New Jersey Department of Environmental Protection, and the Rhode Island Department of Environmental Management.

The most stringent NO_x controls for CTs established as LAER/BACT by state agencies are selective catalytic reduction (SCR) with wet injection and wet injection alone. When SCR has been employed, wet injection is used initially to reduce NO_x emissions. SCR has been installed or permitted in about 132 projects. The majority of these projects (more than 90 percent) are cogeneration facilities with capacities of 50 MW or less. About 83 percent (i.e., 109) of the projects have been in California. Of these 109 projects that have either installed SCR or have been permitted with SCR, 43 percent have been in the Southern California NO_2 nonattainment

Table 4-2. LAER/BACT Decisions For Gas Turbines (Page 1 of 4)

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
Virginia Power	VA	GE turbine	1,875x10^6 BTU/hr	4/88	NO_x 42 ppmvd at 15% O_2 (gas) NO_x 77 ppmvd at 18% O_2 (fuel oil)	Steam injection with maximization NSPS Subpart GG
Trunkline LNG	LA	Gas turbine	147,102 scf/hr	5/87	NO_x 59 lb/hr	
Wichita Falls E. I., I.	TX	Gas turbine	20 MW	6/86	NO_x 684 TPY CO 420 TPY	Steam injection
Merck Sharp and Pohme	PA	Turbine	310x10^6 Btu/hr	5/88	NO_x 42 ppm at 15% O_2	Steam injection
California Dept. of Corr.	CA	Gas turbine	5.1 MW	12/86	NO_x 38 ppmv at 15% O_2	1 to 1 H_2O injection
City of Santa Clara	CA	Gas turbine		1/87	NO_x 42 ppmvd at 15% O_2	Water injection
Combined Energy Resources	CA	Cogeneration Fac.	27 MW	3/87	NO_x 199 lb/day	SCR unit, duct burner, H_2O injection, low NO_x design
Double 'C' Limited	CA	Gas turbine	25 MW	11/86	NO_x 194 lb/day	H_2O injection and SCR 95.80 efficiency
Kern Front Limited	CA	Gas turbine	25 MW	11/86	NO_x 194 lb/day 4.5 ppmvd at 15% O_2	H_2O injection and SCR 95.80 efficiency
Midway - Sunset Project	CA	Gas turbine	973x10^6 Btu/hr	1/87	NO_x 113.4 lb/hr 16.31 ppmv	H_2O injection, 73% efficiency
O'Brien Energy Systems	CA	Gas turbine	359.5x10^6 Btu/day	12/86	NO_x 30.3 lb/hr 15 ppmvd at 15% O_2	Duct burner, H_2O injection and scrubber
PG and E, Station T	CA	GE gas turbine	396x10^6 Btu/hr	8/86	NO_x 25 ppm at 15% O_2 63 lb/hr	Steam injection at steam/fuel ratio of 1.7/1, 75% efficiency
Sierra LTD.	CA	GE gas turbine	11.34x10^6ft^3/day		NO_x 4.04 lb/hr	Scrubber and CO catalytic converter
Sycamore Cogeneration Co.	CA	Gas turbine	75 MW	3/87	CO 10 ppmv at 15% O_2 3 hr average	CO oxidizing catalyst combustion control
U.S. Borax and Chemical Corp.	CA	Gas turbine	45 MW	2/87	NO_x 40 lb/hr 25 ppm at 15% O_2 Dry CO 23 lb/hr	Scrubber Proper combustion techniques
Western Power System, Inc	CA	GE gas turbine	26.5 MW	3/86	NO_x 9 ppmvd at 15% O_2	H_2O injection, SCR 80% efficiency
Calcogen, Cal Polytechic	CA	Gas turbine	21.4 MW	4/84	NO_x 42 ppm at 15% O_2	H_2O injection, 70% efficiency
Greenleaf Power Co.	CA	GE gas turbine	35.62 MW	4/85	NO_x 42 ppm at 15% O_2 91 lb/hr CO 20.41 lb/hr 0.016 lb/10^6 Btu	H_2O injection Good Engineering Practices Steam injection 95.86 efficiency

Table 4-2. LAER/BACT Decisions For Gas Turbines (Page 2 of 4)

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
Greenleaf Power Co.	CA	Duct Burner	63.7x10^6 Btu/hr	4/85	NO_x 0.1 lb/10^6 Btu 6.4 lb/hr CO 0.12 lb/10^6 Btu 7.6 lb/hr	Low NO_x design
OLS Energy	CA	GE gas turbine	256x10^6 Btu/hr	1/86	NO_x 9 ppmvd at 15% O_2	H_2O injection and scrubber 80% efficiency for scrubber
Ciba Giegy Corp.	NJ	Gas turbine	3 MW	1/85	NO_x 11.06 lb/hr CO 9.4 lb/hr	SIP, H_2O injection, 55% efficiency
Energy Reserve, Inc.	CA	Gas turbine	322.5x10^6 Btu/hr	10/85	NO_x 185.4 lb/day	H_2O injection, SCR 92.5% efficiency
Gilroy Energy Co.	CA	Gas turbine	60 MW	8/85	NO_x 25 ppmvd at 15% O_2	Steam injection, quiet combustor
		Auxiliary boiler	90x10^6 Btu/hr		NO_x 40 ppmvd at 3% O_2	Low NO_x burners
Kern Energy Corp.	CA	Gas turbine	8.8x10^6 ft^3/day	4/86	NO_x 8.29 lb/hr 0.023 lb/10^6 Btu	Scrubber with NH_3 reduction agent Steam injection and low NO_x configuration exhaust duct burner 87% efficiency
Moran Power, Inc.	CA	Gas turbine	8.0x10^6 ft^3/day	4/86	NO_x 8.29 lb/hr 0.023 lb/10^6 Btu	Scrubber with NH_3 reduction agent Steam injection and low NO_x configuration exhaust duct burner 87% efficiency
Northern California Power	CA	GE gas turbine	25.8 MW	4/85	NO_x 75 ppm	H_2O injection
Shell California Production	CA	Gas turbine	22 MW	4/85	NO_x 42 ppm at 15% O_2 35 lb/hr CO 10 ppmv at 15% O_2 22 lb/hr	H_2O injection Proper combustion
Southeast Energy, Inc.	CA	Gas turbine	8.0x10^6 ft^3/day	4/86	NO_x 8.29 lb/hr 0.023 lb/10^6 Btu	Scrubber with NH_3 reduction agent Steam injection and low NO_x configuration exhaust duct burner 87% efficiency
Sunlaw/Industrial Park	CA	Gas turbine	412.3x10^6 Btu/hr	6/85	NO_x 9 ppmvd at 15% O_2	Scrubber and steam injection, 80% efficiency
Union Cogeneration	CA	Gas turbine with Duct burner	16 MW	1/86	NO_x 25 ppmv at 15% O_2	H_2O injection and scrubber
Willamette Industries	CA	GE gas turbine	230x10^6 Btu/hr	4/85	NO_x 15 ppmvd at 15% O_2	H_2O injection with SCR 92% efficiency
Witco Chemical Corp.	CA	Gas turbine	350x10^6 Btu/hr	12/84	NO_x 0.18 lb/10^6 Btu oil 0.20 lb/10^6 Btu gas	
		Duct burner	111.6x10^6 Btu/hr		NO_x 0.12 lb/10^6 Btu	Gas firing only

Table 4-2. LAER/BACT Decisions For Gas Turbines (Page 3 of 4)

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
AES Placerita, Inc.	CA	Turbine and Recovery Boiler	519×10^6 Btu/hr	3/86	NO_x 629 lb/day 7 ppmvd at 15% O_2 CO 103 lb/day 2 ppmvd at 15% O_2	H_2O injection, SCR 80% efficiency
AES Placerita, Inc.	CA	Turbine and Recovery Boiler	530×10^6 Btu/hr	7/87	NO_x 340 lb/day 9 ppmvd at 15% O_2	Steam injection, SCR
AES Placerita, Inc.	CA	Gas turbine	530×10^6 Btu/hr	7/87	NO_x 289 lb/day 9 ppmvd at 15% O_2	Steam injection, SCR
Alaska Electrical Generation	AK	Gas turbine	80 MW	3/87	NO_x 75 ppmvd at 15% O_2 CO 109 lb/scf fuel	H_2O injection
Alaska Electrical Generation	AK	Gas turbine	38 MW	3/85	NO_x 75 ppm at 15% O_2	H_2O injection
BAF Energy	CA	Turbine, Generator	887.2×10^6 Btu/hr	7/87	NO_x 9 ppm at 15% O_2 30.1 lb/hr	Steam injection, scrubber 80% efficiency
BAF Energy	CA	Auxiliary Boiler	150×10^6 Btu/hr	10/87	NO_x 17.4 lb/day 40 ppmvd at 3% O_2 CO 63.6 lb/day 0.018 lb/10^6 Btu	Flue gas recirculation Low NO_x burners Oxidation catalyst
Champion International Corp.	TX	Gas turbine	30.6 MW ($1{,}342 \times 10^6$ Btu/hr)	3/85	NO_x 720.34 TPY CO 70.08 TPY	Low NO_x burners
Cogen Technologies	NJ	GE gas turbines	40 MW	6/87	NO_x 9.6 ppmvd at 15% O_2 CO 50 ppmvd at 15% O_2	H_2O injection and SCR, 95% efficiency
Combined Energy Resources	CA	Gas turbine	2 MW	2/88	NO_x 199 lb/hr	H_2O injection and scrubber, 81% efficiency
Formosa Plastic Corp.	TX	GE gas turbine	38.4 MW	5/86	NO_x 640 TPY CO 32.4 TPY	Steam injection
Midland Cogeneration Venture	MI	Turbine Duct burner	984.2×10^6 Btu/hr 249×10^6 Btu/hr	2/88	NO_x 42 ppmv at 15% O_2 CO 26 lb/hr NO_x 0.1 lb/10^6 Btu	Steam injection Turbine design Burner design
Pacific Gas Transmission	OR	Gas turbine	14,000 HP	5/87	NO_x 154 ppm 50 lb/hr CO 6 lb/hr 25 TPY	Combustion control
Power Development Co.	CA	Gas turbine	49×10^6 Btu/hr	6/87	NO_x 36 lb/day 9 ppmvd at 15% O_2	Scrubber and H_2O injection
San Joaquin Cogen Limited	CA	Gas turbine	48.6 MW	6/87	NO_x 250 lb/day 6 ppmvd at 15% O_2 CO 1326 lb/day 55 ppmvd at 15% O_2	Scrubber and H_2O injection 76% efficiency Combustion controls
United Airlines	CA	Gas turbine-Cogeneration	21 MW	12/85	NO_x 15 ppmvd at 15% O_2	SCR and steam injection Oil limited to 500 hours operation

Table 4-2. LAER/BACT Decisions For Gas Turbines (Page 4 of 4)

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
TBG/Grumman	NY	Gas turbine	16 MW	3/88	NO_x 75 ppm + NSPS Corr. 0.2 lb/10^6 Btu CO 0.181 lb/10^6 Btu	H_2O injection and combustion controls CO catalyst
Texas Gas Transmission Corp.	KY	Gas turbine	14,300 HP	2/88	NO_x 0.015% by Volume	
Orlando Utilities Commission	FL	Gas turbine	4 x 445x10^6 Btu/hr	9/88	NO_x 42 ppmvd Gas 65 ppmvd Oil CO 10 ppmvd	Steam injection Good combustion
Anheuser-Busch	FL	Gas turbine	95.7x10^6 Btu/hr	4/87	NO_x 0.1 lb/10^6 Btu	
Ocean State Power	RI	Combined Cycle	500 MW	1/89	NO_x 9 ppmvd at 15% O_2 (Natural Gas) NO_x 42 ppmvd at 15% O_2 (fuel oil) CO 25 ppmvd at 15% O_2	SCR and steam injection
Pawtucket Power	RI	Cogeneration-Gas turbine	58 MW	2/89	NO_x 9 ppmvd at 15% O_2 (natural gas) NO_x 18 ppmvd at 15% O_2 (fuel oil) CO 23 ppmvd at 15% O_2	SCR and steam injection
Cogen Technologies	NJ	Gas turbine	55 MW	3/87	NO_x 9 ppmvd at 15% O_2 (natural gas) NO_x 14 ppmvd at 15% O_2 (fuel oil) CO 8 ppm; 20 ppm NH_3	SCR and wet injection

area where SCR was required not as BACT but as LAER, a more stringent requirement. LAER is distinctly different from BACT in that there is no consideration of economic, energy, or environmental impacts; if a control technology has previously been installed, it must be required as LAER. LAER is defined as follows:

> Lowest achievable emission rate means, for any source, the more stringent rate of emissions based on the following: (i) The most stringent emissions limitation which is contained in the implementation plan of any State of such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or (ii) The most stringent emissions limitation which is achieved in practice by such class or category of stationary source. This limitation, when applied to a modification, means the lowest achievable emissions rate for the new or modified emissions units within the stationary source. In no event shall the application of this term permit a proposed new modified stationary source to emit any pollutant in excess of the amount allowable under applicable new source standards of performance (40 CFR 51 Appendix S. II, A.18).

As noted from the discussion contained in Section 3.2.3, there are distinct regulatory and policy differences between LAER and BACT.

All the projects in California have natural gas as the primary fuel, and only 15 of the SCR applications in California have distillate fuel as backup.

The remaining projects with SCR (i.e., 23 projects) are located in the eastern United States. These projects are located in Vermont, Massachusetts, Connecticut, New Jersey, New York, Rhode Island, and Virginia. A majority of these projects are cogenerators or independent power producers. The size of these projects ranges from 22 MW to 450 MW, with 87 percent less than 100 MW in size. While almost all of the facilities have distillate oil as backup fuel, distillate oil is generally restricted by permit to 1,000 hours per CT or less.

Reported and permitted NO_x removal efficiencies of SCR range from 40 to 80 percent. The most stringent emission limiting standards associated with SCR are approximately 9 ppm for natural gas firing. However, two facilities have reported emission limits of about 4.5 ppm. These emission limits were clearly determined to be LAER on CTs using water injection with uncontrolled NO_x levels below 42 ppm. For fuel oil firing, permitted NO_x emission limits with SCR have ranged from 14 ppm to 42 ppm. SCR has not been installed or permitted on simple-cycle CTs.

Wet injection is the primary method of reducing NO_x emissions from CTs. This method of control was first mandated by the NSPS to reduce NO_x levels to 75 parts per million by volume, dry (ppmvd) (corrected to 15 percent O_2 and heat rate). Development of improved wet injection combustors reduced NO_x concentrations to 25 ppmvd and 42 ppmvd (corrected to 15 percent O_2) when burning natural gas and fuel oil, respectively. Recently, CT manufacturers have developed dry low NO_x combustors that can reduce NO_x concentrations to 25 ppmvd (corrected to 15 percent O_2) when firing natural gas.

In Florida, a majority of the most recent PSD permits and BACT determinations for simple-cycle gas turbines have required wet injection for NO_x control. The emission limits included in these permits and BACT determinations were 42 ppm and 65 ppm (corrected to 15 percent O_2, dry conditions), respectively, for natural gas and fuel oil firing. In November 1990, FDER determined that a CT using a dry low NO_x combustor to reduce NO_x concentrations to 25 ppmvd when firing natural gas was BACT. The corresponding BACT emission limit for distillate oil firing was 65 ppmvd using wet injection.

4.3.1.2 Technology Description and Feasibility

Selective Catalytic Reduction (SCR)--SCR uses ammonia (NH_3) to react with NO_x in the gas stream in the presence of a catalyst. NH_3, which is diluted with air to about 5 percent by volume, is introduced into the gas stream at reaction temperatures between 570°F and 750°F. The reactions are as follows:

$$4NH_3 + 4NO + O_2 = 4N_2 + 6H_2O$$

$$4NH_3 + 2NO_2 + O_2 = 3N_2 + 6H_2O$$

SCR operating experience, as applied to gas turbines, consists primarily of baseload natural-gas-fired installations either of cogeneration or combined-cycle configuration; no simple-cycle facilities have SCR. Exhaust gas temperatures of simple-cycle CTs are generally in the range of 1,000°F, which exceeds the optimum range for SCR. All current SCR applications have the catalyst placed in the heat recovery steam generators (HRSG) to achieve proper reaction conditions. This allows a relatively constant temperature for the reaction of NH_3 and NO_x on the catalyst surface.

The use of SCR has been limited to facilities that burn natural gas or small amounts of fuel oil since SCR catalysts are contaminated by sulfur-containing fuels (i.e., fuel oil). For most fuel oil burning facilities, catalyst operation is discontinued, or the exhaust bypasses the SCR system. While the operating experience has not been extensive, certain cost, technical, and environmental considerations have surfaced. These considerations are summarized in Table 4-3. Experience at the United Airlines cogeneration facility using Jet A fuel oil found catalyst contamination after 2,500 hours of operation. For this facility, the catalyst has been replaced three times and the recommended duration of operation by the manufacturer is now 500 hours.

As presented in Table 4-3, ammonium bisulfate is formed by the reaction of NH_3 and sulfur trioxide (SO_3). Ammonium bisulfate can be corrosive and could cause damage to the HRSG surfaces that follow the catalyst, as well as to the stack. Corrosion protection for these areas would be required.

Zeolite catalysts, which are reported to be capable of operating in temperature ranges from 600°F to 950°F, have been available commercially only recently. Their application with SCR primarily has been limited to internal combustion engines. Optimum performance of an SCR system using a zeolite catalyst is reported to range from about 800°F to 900°F. The exhaust temperatures of the proposed CTs for the DeBary site are expected

Table 4-3. Cost, Technical and Environmental Considerations of SCR Utilized on Combustion Turbines (Page 1 of 2)

Consideration	Description
COST:	
Catalyst Replacement	Catalyst life varies depending on the application. Cost ranges from 20 to 40 percent of total capital cost and is the dominant annual cost factor.
Ammonia	Ratio of at least 1:1 NH_3 to NO_x generally needed to obtain high removal efficiencies. Special storage and handling equipment required.
Space Requirements	For new installations, space in the catalyst is needed for replacement layers. Additional space is also required for catalyst maintenance and replacement.
Backup Equipment	Reliability requirements necessitate redundant systems such as ammonia control and vaporization equipment.
Catalyst Back Pressure Heat Rate Reduction	Addition of catalyst creates back pressure on the turbine which reduces overall heat rate.
TECHNICAL:	
Ammonia Flow Distribution	NH_3 must be uniformly distributed in the exhaust stream to assure optimum mixing with NO_x prior to reaching the catalyst.
Temperature	The narrow temperature range that SCR systems operate within, i.e., about 100°F, must be maintained even during load changes. Operational problems could occur if this range is not maintained. HRSG duct firing requires careful monitoring.
Ammonia Control System	Quantity of NH_3 introduced must be carefully controlled. With too little NH_3, the desired control efficiency is not reached; with too much NH_3, NH_3 emissions (referred to as slip) occur.

Table 4-3. Cost, Technical and Environmental Considerations of SCR Utilized on Combustion Turbines (Page 2 of 2)

Consideration	Description
Flow Control	The velocity through the catalyst must be within a range to assure satisfactory residence time.
ENVIRONMENTAL:	
Ammonia Slip	NH_3 slip, or NH_3 that passes unreacted through the catalyst and into the atmosphere, can occur if: 1) too much ammonia is added, 2) the flow distribution is not uniform, 3) the velocity is not within the optimum range, or the proper temperature is not maintained.
Ammonia Bisulfate	Ammonium bisulfate salts can lead to increased corrosion. These salts usually occur when firing fuel oil. These compounds are emitted as particulates.
N_2O and Nitrosoamines formation	The mechanism under which these compounds form is not totally understood. Secondary impacts can occur.

to be in excess of 1,000°F. At temperatures of 1,000°F and above, the zeolite catalyst will be irreparably damaged. Therefore, application of an SCR system using a zeolite catalyst on a simple-cycle operation is technically infeasible without exhaust gas cooling. Moreover, since zeolite catalysts have not been operated continuously in combustion exhausts greater than 900°F, the cooling system would have to reduce turbine exhaust temperatures about 200°F, i.e., to around 800°F.

Attemperation systems are neither commercially available nor have they been applied, even at a pilot stage, to SCR systems associated with simple-cycle CTs. Three types of potential attemperation systems include water sprays, air dilution, and indirect heat exchangers. The application of water sprays and air dilution would require sufficient distribution and mixing volume to assure uniform temperature throughout the catalyst. This would be extremely difficult to achieve in the size of CTs proposed because of their large and turbulent flowrate [greater than 1,500,000 actual cubic feet per minute (acfm)]. If the temperature was not uniform, the catalyst would be irreversibly damaged in areas where the exhaust temperatures approach 1,000°F. In addition, at temperatures above 950°F, the ammonia injected to achieve the NO_x reduction could itself be oxidized to NO_x, the pollutant it was intended to remove. Indirect heat exchanges could reduce temperatures but have not been developed for this application. Application of any attemperation technique would require research and development that is beyond that considered appropriate by EPA regulations and guidelines.

<u>Wet Injection</u>--The injection of water or steam in the combustion zone of CTs reduces the flame temperature with a corresponding decrease of NO_x emissions. The amount of NO_x reduction possible depends on the combustor design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the CT becomes inefficient and unreliable, and significant increases in products of incomplete combustion will occur (i.e., CO and VOC emissions).

For the CTs being considered for the DeBary site, the combustion chamber design includes water injection using the GE "quiet combustor." This multiple-nozzle combustor was developed to increase the amount of steam or water injected into the combustion zone while reducing the dynamic pressure oscillations. High dynamic pressure oscillations in standard combustors lead to reduced combustor life. The first endurance test of a quiet combustor was at Houston Light and Power Company's Wharton Station in the early 1980s. In the late 1980s, the first production units were installed in California. The lowest NO_x emission level guaranteed by GE for the quiet combustor is 42 ppmvd (corrected to 15 percent O_2) when firing fuel oil and 25 ppmvd (corrected to 15 percent O_2) when firing natural gas.

Dry Low NO_x Combustor--In the last several years, CT manufacturers have offered and installed machines with dry low NO_x combustors. These combustors, which are offered on machines manufactured by GE, Kraftwork Union, and Asea Brown Boveri (ABB), can achieve NO_x concentrations of 25 ppmvd or less when firing natural gas. Thermal NO_x formation is inhibited by using combustion techniques where the natural gas and combustion air are premixed prior to ignition. However, when firing oil, NO_x emissions are controlled only through water or steam injection to exhaust concentrations of 65 ppmvd. Since distillate oil is the primary fuel for the DeBary CTs, the use of the dry low NO_x combustor for the project will have no advantage in reducing NO_x concentrations.

NO_xOUT Process--The NO_xOUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO_x. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NO_xOUT process, aqueous urea is injected into the flue gas stream ideally within a temperature range of 1,600°F to 1,900°F. In the presence of oxygen, the following reaction results:

$$CO(NH_2)_2 + 2NO + 1/2\ O_2 \dashrightarrow 2N_2 + CO_2 + 2H_2O$$

The amount of urea required is most cost effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,000°F and 1,950°F. Advantages of the system are:

1. Low capital and operating costs due to utilization of urea injection, and
2. The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems.

Disadvantages of the system are:

1. Formation of ammonia from excess urea treatment rates and/or improper use of reagent catalysts; and
2. SO_3, if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold end equipment downstream.

Commercial application of the NO_xOUT system is limited to three reported cases:

1. Trial demonstration on a 62.5-ton-per-hour (TPH) stoker-fired wood waste boiler with 60 to 65 percent NO_x reduction,
2. A 600 x 10^6 Btu CO boiler with 60 to 70 percent NO_x reduction, and
3. A 75 MW pulverized coal-fired unit with 65 percent NO_x reduction.

The NO_xOUT system has not been demonstrated on any stationary internal combustion engine.

The NO_xOUT process is not technically feasible for the proposed lean-burn engine due to the high application temperature of 1,000°F to 1,950°F. The exhaust gas temperature of the CT is about 1,000°F. Raising the exhaust temperature the required amount essentially would require installation of a heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_x.

Thermal $DeNO_x$--Thermal $DeNO_x$ is Exxon Research and Engineering Company's patented process for NO_x reduction. The process is a high temperature selective noncatalytic reduction (SNCR) of NO_x using ammonia as the reducing agent. Thermal $DeNO_x$ requires the exhaust gas temperature to be above 1,800°F. However, use of ammonia plus hydrogen lowers the temperature requirement to about 1,000°F. For some applications, this must be achieved by additional firing in the exhaust stream prior to ammonia injection.

The only known commercial applications of Thermal $DeNO_x$ are on heavy industrial boilers, large furnaces, and incinerators that consistently produce exhaust gas temperatures above 1,800°F. There are no known applications on or experience with CTs. Temperatures of 1,800°F require alloy materials constructed with very large size piping and components since the exhaust gas volume would be increased by several times. As with the NO_xOUT process, high capital, operating, and maintenance costs are expected because of construction-specified material, an additional duct burner system, and fuel consumption. Uncontrolled emissions would increase because of the additional fuel burning.

Thus, the Thermal $DeNO_x$ process will not be considered for the proposed project because it is technically infeasible because of its high application temperature. The exhaust gas temperature of a lean-burn engine is typically about 1,000°F; the cost to raise the exhaust gas to such a high temperature is prohibitively expensive.

Nonselective Catalytic Reduction--Certain manufacturers, such as Engelhard, market a nonselective catalytic reduction system (NSCR) for NO_x control on reciprocating engines. The NSCR process requires a low oxygen content in the exhaust gas stream and high temperature (700°F to 1,400°F) in order to be effective. CTs have the required temperature but also high oxygen levels (greater than 12 percent) and, therefore, cannot use the NSCR process. As a result, NSCR is not a technically feasible add-on NO_x control device for CTs.

<u>Summary of Technically Feasible NO_x Control Methods</u>--The available information suggests that SCR with wet injection is technically infeasible for simple-cycle operation. SCR with wet injection has not been applied to simple-cycle CTs.

A technical evaluation of tail gas controls (i.e., SCR, NO_xOUT, Thermal DENO_x, and NSCR) indicates that these processes have not been applied to simple-cycle CTs and are technically infeasible for the project due to process constraints (e.g., temperature). Dry low NO_x combustors are inappropriate for the project since distillate oil is the primary fuel and natural gas will not be used initially.

Wet injection is a technically feasible alternative for the DeBary CTs. The application of this technology has the following limitations:

1. Wet injection can be accomplished until a condition of maximum moisturization occurs; this design condition occurs at 42 ppm with fuel oil.
2. Wet injection will not reduce substantially NO_x formation caused by fuel-bound nitrogen. Any emission-limiting requirements must account for this effect.
3. Wet injection will increase the emissions of CO and VOC. Emissions are dependent on the water-to-fuel ratio.

For the BACT analysis, wet injection capable of achieving NO_x emission levels to 42 ppm when firing fuel oil (corrected to 15 percent O_2 dry conditions) was assumed. These emission levels are the most stringent being established as BACT for simple-cycle CTs.

4.3.1.3 Impact Analysis

A BACT determination requires an analysis of the economic, environmental, and energy impacts of the proposed and alternative control technologies [see 40 CFR 52.21(b)(12), Chapter 17-2.100(25), F.A.C., and Chapter 17-2.500(5)(c), F.A.C.]. The analysis must, by definition, be specific to the project, i.e., case-by-case. The BACT analysis was performed for wet injection at an emission rate of 42 ppmvd corrected to 15 percent O_2 when firing oil.

Economic--The total capital and annualized capital cost for the quiet combustor is presented in Table 4-4.

Environmental--The maximum predicted impacts of the alternative technologies are all considerably below the PSD increment for NO_x of 25 $\mu g/m^3$, annual average, and the AAQS for NO_x of 100 $\mu g/m^3$.

Energy--The use of the quiet combustor will affect energy production in two ways. First, the heat rate will increase about 1 percent (at ISO conditions) compared to the standard combustor, which requires less fuel to generate the same amount of power. This energy penalty will be about 500 British thermal units per kilowatt hour (Btu/kWh).

Second, water injection will increase power by about 5 percent over the standard combustor, for a net power benefit of about 5 MW. Since the primary purpose of the DeBary project is to provide peaking power, the benefit of increased power offsets the increased heat rate.

4.3.1.4 Proposed BACT and Rationale

The proposed BACT for the DeBary CTs is wet injection. The proposed NO_x emissions levels using wet injection are 42 ppmvd (corrected) when firing

Table 4-4. Capital and Annualized Capital Costs for GE Quiet Combustor and Water Injection Equipment[a]

Cost Category	Capital Costs[b] ($1,000)
Combustion Turbine Generators (6)	
Multi-Nozzle Quiet Combustor	3,000
Water Injection Skid	1,600
On-Base Water Injection Equipment	100
Foundations	500
Water Treatment Building	300
Site Improvements	100
Water Storage and Piping Systems	1,600
Water Treatment Equipment	2,300
Electrical and Control Systems	2,200
Miscellaneous	800
TOTAL DIRECT COST	12,500
Annualized Capital Cost (at 10 percent over 20 years)	1,468

[a] Based on preliminary engineering design concepts for all six combustion turbine units.
[b] Excludes any applicable taxes.

Source: Black & Veatch, 1990.

fuel oil and 25 ppmvd (corrected) when firing natural gas. This control technology is proposed for the following reasons:

1. SCR was rejected based on technical infeasibility. SCR has not been applied to or demonstrated on simple-cycle CTs.
2. The proposed BACT of wet injection provides the least costly control alternative and results in low environmental impacts (less than 1 percent of the allowable PSD increments and less than 1 percent of the AAQS for NO_x). Wet injection at the proposed emissions levels has been adopted previously in BACT determinations. In addition, the CT manufacturer (i.e., GE) has been willing to guarantee this level of NO_x emissions.

The proposed BACT emission level should also account for fuel-bound nitrogen (FBN) content greater than 0.015 percent since there is no practicable means for reducing NO_x at higher FBN levels. The allowance specified in the NSPS for FBN levels greater than 0.015 percent is requested.

4.3.2 CARBON MONOXIDE (CO)

4.3.2.1 Emission Control Hierarchy

CO emissions are a result of incomplete or partial combustion of fossil fuel. Combustion design and catalytic oxidation are the control alternatives that are viable for the project.

Combustion design is the more common control technique used in CTs. Sufficient time, temperature, and turbulence is required within the combustion zone to maximize combustion efficiency and minimize the emissions of CO. Combustion efficiency is dependent upon combustor design. When wet NO_x control systems are employed, the amount of water or steam injected in the combustion zone also affects combustion efficiency. For the CTs being evaluated and with wet injection NO_x control, CO emissions range from 25 ppm to 35 ppm, corrected to dry conditions.

Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use LAER technology and typically have CO limits in the 10 ppm range (corrected to dry conditions).

4.3.2.2 Technology Description

In an oxidation catalyst control system, CO emissions are reduced by allowing unburned CO to react with oxygen at the surface of a precious metal catalyst such as platinum. Combustion of CO starts at about 300°F, with efficiencies above 90 percent occurring at temperatures above 600°F. Catalytic oxidation occurs at temperatures 50 percent lower than that of thermal oxidation, which reduces the amount of thermal energy required. For CTs, the oxidation catalyst can be located directly after the CT. Catalyst size depends upon the exhaust flow, temperature, and desired efficiency. The existing oxidation catalyst applications have primarily been limited to smaller cogeneration facilities burning natural gas.

Oxidation catalysts have not been used on fuel-oil-fired CTs or combined cycle facilities. The use of sulfur-containing fuels in an oxidation catalyst system would result in an increase of SO_3 emissions and concomitant corrosive effects to the stack. In addition, trace metals in the fuel could result in catalyst poisoning during prolonged periods of operation.

Since the units likely will require numerous startups, variations in exhaust conditions will influence catalyst life and performance. Very little technical data exist to demonstrate the effect of such cycling.

The lack of demonstrated operation with oil firing suggests rejection of catalytic oxidation as a technically feasible alternative. However, the advent of a second generation catalyst suggests that an oxidation catalyst could be used.

Combustion design is dependent upon the manufacturer's operating specifications, which include the air-to-fuel ratio and the amount of water injected. The CTs proposed for the project have designs to optimize combustion efficiency and minimize CO emissions. Installations with an oxidation catalyst and combustion controls generally have controlled CO levels of 10 ppm as LAER and BACT.

For the DeBary CTs, the following alternatives were evaluated for natural gas firing or BACT:

1. Oxidation catalyst at 10 ppmvd; maximum CO emissions are 564 TPY (59°F).
2. Combustion controls at 25 ppmvd; maximum emissions are 1,411 TPY (59°F).

4.3.2.3 Impact Analysis

Economic--The estimated annualized cost of a CO oxidation catalyst is $6,252,000 (Table 4-5) with a cost effectiveness of $7,380/ton of CO removed. The cost effectiveness is based on CT emissions of 25 ppmvd. No costs are associated with combustion techniques since they are inherent in the design.

Environmental--The air quality impacts of both oxidation catalyst control and combustion design control techniques are below the significant impact levels for CO. Therefore, no significant environmental benefit would be realized by the installation of a CO catalyst.

Energy--An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 2 inches water gauge would be expected. At a catalyst back pressure of about 2 inches, an energy penalty of about 9,800,000 kWh/yr would result at 100 percent load. This energy penalty is sufficient to supply the electrical needs of about 800 residential customers over a year. Fuel oil usage would effectively increase by about 810,000 gallons/year.

Table 4-5. Capital and Annualized Cost for Oxidation Catalyst

Cost Component	Cost ($)	Basis
I. CAPITAL COSTS		
A. DIRECT:		
1. Associated Equipment for Catalyst	1,093,750	Manufacturer's Estimate - $1,750 per lb/sec mass flow
2. Exhaust Stack Modification	900,000	Engineering Estimate - $150,000/CT
3. Installation	2,047,917	25% of Equipment Costs (I.A.1. & 2., and II.A.)
B. INDIRECT:		
1. Engineering & Supervision	614,375	7.5% of Equipment Costs (I.A.1. & 2., and II.A.)
2. Construction and Field Expense	819,167	10% of Equipment Costs (I.A.1. & 2., and II.A.)
3. Construction Contractor Fee	409,583	5% of Equipment Costs (I.A.1. & 2., and II.A.)
4. Startup & Testing	163,833	2% of Equipment Costs (I.A.1. & 2., and II.A.)
5. Contingency	1,512,156	25% of Direct and Indirect Capital Costs (I.A, and I.B.1-4)
6. AFUDC	1,651,044	12% of Direct and Indirect Capital Costs, and Recurring Capital Costs (I.A., I.B.1.-4 and II.A.)
TOTAL CAPITAL COSTS	9,211,825	Sum of Direct and Indirect Capital Costs
ANNUALIZED CAPITAL COSTS	1,082,018	Capital Recovery of 10% over 20 years
II. RECURRING CAPITAL COSTS		
A. Catalyst	6,197,917	Manufacturer's Estimate - $1,750 per lb/sec mass flow
B. Contingency	1,549,479	25% of Recurring Capital Costs (II.A)
TOTAL RECURRING CAPITAL COSTS	7,747,396	Sum of Recurring Capital Costs
ANNUALIZED RECURRING CAPITAL COSTS	3,115,343	Capital Recovery of 10% over 20 years
III. OPERATING & MAINTENANCE COSTS		
A. DIRECT:		
1. Labor - Operator & Supervisor	10,525	8 hours/week, 52 weeks/year, $22/hour and 15% supervisor cost
2. Maintenance	84,796	0.5% of Total and Recurring Capital Costs
3. Inventory Cost	121,334	Capital Carrying cost (10% over 20 years) for catalyst for 1 CT
B.ENERGY COSTS		
1. Heat Rate Penalty	834,141	0.2% heat rate penalty. $7.71/million Btu fuel cost
2. MW Loss Penalty	66,881	0.2% MW loss; $60,000/MW replacement assumed
3. Fuel Escalation Costs	220,380	Fuel escalation of 3% over inflation; annualized over 20 years
C. INDIRECT:		
1. Overhead	57,193	60% of Labor and Maintenance Costs (III.A.1. and 2.)
2. Property Taxes	169,592	1% of Total and Recurring Capital Cost
3. Insurance	169,592	1% of Total and Recurring Capital Cost
4. Administration	339,184	2% of Total and Recurring Capital Cost
ANNUALIZED CAPITAL COSTS	1,082,018	
ANNUALIZED RECURRING CAPITAL COSTS	3,115,343	
OPERATING AND MAINTENANCE COSTS	2,073,618	
TOTAL ANNUALIZED COSTS	6,270,979	Sum of Operating and Maintenance and Annualized Capital Costs

Note: All calculations using machine performance were based on 59°F conditions. Assumptions based on percentage of costs were adapted from EPA OAQPS Control Cost Manual (1990).

4.3.2.4 Proposed BACT and Rationale

Combustion design is proposed as BACT as a result of the technical and economic consequences of using catalytic oxidation on CTs. Catalytic oxidation is considered infeasible and unreasonable for the following reasons:

1. Catalytic oxidation has not been demonstrated on a continuous basis when using fuel oil; and
2. The economic impacts are significant (i.e., an annualized cost of almost $63 million, with a cost effectiveness of over $7,380/ton of CO removed).

4.3.3 SULFUR DIOXIDE (SO_2)

4.3.3.1 Emission Control Hierarchy

Sulfur dioxide (SO_2) emissions are a result of the oxidation of sulfur in fossil fuel and can be minimized by reducing the sulfur content in fuel or through applying post-combustion removal techniques. For CTs, the use of low sulfur fuels is the only demonstrated control technology determined to be technically feasible. Post-combustion techniques, such as flue gas desulfurization (FGD), have not been applied to CTs.

FGD systems have been applied to oil- and coal-fired steam electric power plants. However, the relative gas volume for such facilities is significantly less than that for CTs (i.e., about 2 to 3 times), and the resultant SO_2 concentration is considerably higher. While the former factor will influence the cost of FGD, the latter poses significant technological constraints to removing SO_2. As a result, FGD is not feasible for application to CTs.

The BACT/LAER clearinghouse documents (EPA, 1985b, 1986, 1987c, and 1988c) show that fuel sulfur contents from 0.8 percent to less than 0.2 percent have been specified as BACT for CTs. The lowest sulfur-containing fuels were required in California and New Jersey, where LAER decisions dictated more stringent standards. Furthermore, such requirements generally limited fuel oil use for backup or emergency purposes only.

In Florida, CTs have been permitted recently with sulfur limitations of 0.2 and 0.3 percent annual average and 0.5 percent maximum. These facilities include the Florida Power and Light Company (FPL) Lauderdale Repowering Project, the Hardee Power Station, and the FPL Martin project. However, the primary fuel for these facilities was natural gas.

For the proposed CTs, the only technically feasible control technology for SO_2 is low sulfur fuel use. The use of natural gas will minimize SO_2 emissions but is not available at the site. SO_2 emissions from distillate fuel can be minimized by specification of a lower sulfur content fuel. A maximum sulfur content of 0.3 percent was selected as the top-down BACT level since it is near the lowest of the average sulfur contents permitted by FDER in mid-1990.

4.3.3.2 Technology Description

The No. 2 fuel oil used in the proposed CTs will have a maximum sulfur content specification of 0.5 percent. For the purposes of this analysis, the maximum sulfur content of 0.5 percent was assumed.

The maximum emissions on No. 2 fuel oil would be 14,581 TPY (see Table A-2; 59°F) and would be 8,749 TPY on a fuel with a maximum sulfur content of 0.3 percent.

4.3.3.3 Impact Analysis

Economic--The differential annualized present worth cost of using 0.3 percent sulfur oil in place of 0.5 percent sulfur fuel oil is $4,608,102. This was calculated assuming an initial difference of 0.62 percent between a specification of 0.5 percent and 0.3 percent oil and a fuel escalation rate of 3 percent over inflation. The resulting cost effectiveness is $790/ton of SO_2 removed. However, the weighted average sulfur content for No. 2 fuel oil received at DeBary over the last 5 years has been 0.305 percent (see Table 4-6). Therefore, no benefit likely would result from specifying a maximum sulfur content of 0.3 percent.

Table 4-6. Actual Sulfur Content and Fuel Use of No. 2 Distillate Fuel Oil at the DeBary Plant

Year	Sulfur Content (%)	Fuel Use (1,000 gal)
1989	0.327	11,699
1988	0.259	4,816
1987	0.33	4,190
1986	0.18	467
1985	0.22	912

Weighted Average Sulfur Content = 0.305 percent

Environmental--Based upon use of 0.5 percent sulfur fuel oil, the maximum SO_2 impacts of the proposed turbines alone will be less than 5 percent of the AAQS for SO_2, and less than 13 percent of the allowable PSD Class II increments. As a result, significant air quality benefits will not occur by reducing fuel sulfur content below that in No. 2 fuel oil.

Energy--No substantial energy penalties are expected to result from using No. 2 fuel oil with different sulfur contents.

4.3.3.4 Proposed BACT and Rationale

The proposed BACT for the proposed turbines is the use of No. 2 fuel oil with a maximum sulfur content of 0.5 percent. The selection of this control alternative is based upon the following:

1. Requiring a maximum sulfur content of 0.5 percent likely would result in an average sulfur content much less than 0.5 percent as evidenced by actual sulfur content of No. 2 fuel oil over the last 5 years.
2. No. 2 fuel oil is the primary fuel for the CTs and, therefore, any requirement for specifying a lower maximum sulfur content would have a direct economic impact on their use.
3. Fuel management to reduce the annual average sulfur content to 0.3 percent (as required by recent BACT determinations) would not be practical since those units will be used for peaking service. The only way to assure that an annual average limit would be achieved is to specify a maximum sulfur content of 0.3 percent. For example, a 0.3 percent annual average sulfur limit could be exceeded if the average sulfur content was greater than 0.3 percent in the first half of the year and the units were not required to operate the remaining portion of the year.
4. The location of the DeBary site (i.e., distance from primary fuel delivery ports) makes fuel management impractical to achieve an annual average sulfur content of 0.3 percent. There are no

sufficient tanks at the sites to store and mix various sulfur content distillate oils.

5. There is no significant environmental benefit in using fuel oil with less than 0.5 percent sulfur content maximum.

4.3.4 PARTICULATE EMISSIONS/PM10

The emission of particulates from the CTs is a result of incomplete combustion and trace solids in the fuel (particularly fuel oil) and in the injected water or steam used for NO_x control. The design of the CTs ensures that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on oil- or gas-fueled CTs. The No. 2 (i.e. distillate) fuel oil to be used in the CTs will contain only trace quantities of particulate (i.e., typically about 0.05 percent ash or less in fuel oil). Therefore, the use of clean fuel and combustion design is the proposed BACT for PM(TSP) and PM10.

The maximum particulate emissions from the CTs when burning fuel oil will be a lower concentration than that normally specified for fabric filter designs; i.e., the grain loading associated with the maximum particulate emissions [about 15 pounds per hour (lb/hr)] is less than 0.01 grains per standard cubic foot (gr/scf), which is a typical design specification for a baghouse. This further demonstrates that no further particulate controls are necessary for the proposed project.

4.3.5 OTHER REGULATED AND NONREGULATED POLLUTANT EMISSIONS

The PSD source applicability analysis shows that PSD significant emission levels are exceeded for H_2SO_4 mist, Hg, Be, and As, requiring PSD review (including BACT) for these pollutants.

There are no technically feasible methods for controlling the emissions of these pollutants from CTs, other than the inherent quality of the fuel (see Sections 4.3.3 and 4.3.4). Sulfuric acid mist emissions are a direct function of the sulfur content of the fuel. Levels of trace metals in No. 2 distillate oil are limited by fuel oil specifications. Low sulfur No. 2 distillate oil represents BACT for these pollutants.

For the nonregulated pollutants, most of which are trace metals, none of the control technologies evaluated for other pollutants (i.e., oxidation catalyst) would reduce such emissions and low sulfur distillate oil represents BACT because of its inherent low metals content.

5.0 AIR QUALITY MONITORING DATA

5.1 PSD PRECONSTRUCTION

The CAA requires that an air quality analysis be conducted for each pollutant subject to regulation under the act before a major stationary source or major modification is constructed. This analysis may be performed by the use of modeling and/or monitoring the air quality. The use of monitoring data refers to either the use of representative air quality data from existing monitoring stations or establishing a monitoring network to monitor existing air quality. Monitoring must be conducted for a period up to 1 year prior to submission of a construction permit application. In addition to establishing existing air quality, the air quality data are useful for determining background concentrations (i.e., concentrations from sources not considered in the modeling). The background concentrations can be added to the concentrations predicted for the sources considered in the modeling to estimate total air quality impacts. These total concentrations are then evaluated to determine compliance with the AAQS.

For the criteria pollutants, continuous air quality monitoring data must be used to establish existing air quality concentrations in the vicinity of the proposed source or modification. However, preconstruction monitoring data will generally not be required if the ambient air quality concentration before construction is less than the de minimis impact monitoring concentrations (refer to Table 3-2 for de minimis impact levels). Also, if the maximum predicted impact of the source or modification is less than the de minimis impact monitoring concentrations, the source would generally be exempt from preconstruction monitoring.

For noncriteria pollutants, EPA recommends that an analysis based on air quality modeling generally should be used instead of monitoring data. The permit-granting authority has discretion in requiring preconstruction monitoring data when:

1. The state has an air quality standard for the noncriteria pollutant and emissions from the source or modification pose a threat to the standard;
2. The reliability of emission data used as input to modeling existing sources is highly questionable; or
3. Air quality models have not been validated or may be suspect for certain situations, such as complex terrain or building downwash conditions.

However, if the maximum concentrations from the major source or major modification are predicted to be above the significant monitoring concentrations, EPA recommends that an EPA-approved measurement method be available before a permit-granting authority requires preconstruction monitoring.

EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD) (EPA, 1987a) sets forth guidelines for preconstruction monitoring. The guidelines allow the use of existing air quality data in lieu of additional air monitoring, if the existing data are representative. The criteria used in determining the representativeness of data are monitor location, quality of data, and currentness of data.

For the first criterion, monitor location, the existing monitoring data should be representative of three types of areas:

1. The location(s) of maximum concentration increase from the proposed source or modification;
2. The location(s) of the maximum air pollutant concentration from existing sources; and
3. The location(s) of the maximum impact area, i.e., where the maximum pollutant concentration would hypothetically occur based on the combined effect of existing sources and the proposed new source or modification.

Basically, the locations and size of the three types of areas are determined through the application of air quality models. The areas of maximum concentration or maximum combined impact vary in size and are influenced by factors such as the size and relative distribution of ground level and elevated sources, the averaging times of concern, and the distances between impact areas and contributing sources.

For the second criteria, data quality, the monitoring data should be of similar quality as would be obtained if the applicant were monitoring according to PSD requirements. As a minimum, this would mean:

1. Use of continuous instrumentation,
2. Production of quality control records that indicate the instruments' operations and performances,
3. Operation of the instruments to satisfy quality assurance requirements, and
4. Data recovery of at least 80 percent of the data possible during the monitoring effort.

For the third criteria, currentness of data, the monitoring data must have been collected within a 3-year period preceding the submittal of permit application and must still be representative of current conditions.

5.2 PROJECT MONITORING APPLICABILITY

As determined by the source applicability analysis described in Section 2.4, an ambient monitoring analysis is required by PSD regulations for SO_2, NO_2, PM, CO, H_2SO_4 mist, radionuclides, and AS emissions. Although H_2SO_4 mist, radionuclides, and As are required to undergo air quality analyses, these pollutants may be exempt from monitoring requirements because no acceptable monitoring techniques have been established. The maximum predicted impacts from the proposed turbines are less than de minimis levels for SO_2, NO_2, PM, and CO. Therefore, preconstruction monitoring is not required for those pollutants for this project.

In May 1990, FPC submitted to FDER a preliminary air quality impact assessment of the proposed simple-cycle CTs. The assessment described the maximum predicted impacts due to the turbines based on preliminary design information and recommended the use of existing FDER air quality monitoring data that would be appropriate to satisfy PSD preconstruction monitoring requirements. (The predicted impacts produced for the proposed design information presented in this report are less than the de minimis levels; therefore, preconstruction monitoring would not be required.) In July 1990, FDER determined that data collected at the recommended site in Volusia County was acceptable for satisfying this requirement (see Appendix B). The monitoring site's identification number and location relative to the DeBary Plant are given in Table 5-1. A summary of the SO_2 data recorded at this monitoring site from 1986 through January 1989 is presented in Table 5-2.

The monitoring site is operated by FDER and meets all quality assurance requirements. As shown in Table 5-2, all data recoveries have exceeded the requirement of 80 percent recovery. Because the data have been gathered within the last 3 years, the data are considered to be representative of current conditions.

5.3 BACKGROUND CONCENTRATIONS

Background SO_2 concentrations must be estimated to account for sources which are not explicitly included in the atmospheric dispersion modeling analysis. The available ambient SO_2 data presented in Table 5-2 were used for this purpose, based on the latest full year of data (i.e., 1988). For the short-term averaging times, the second-highest 3- and 24-hour average concentrations of 90 and 25 $\mu g/m^3$, respectively, were used as background concentrations. For the annual averaging time, the annual average concentration of 4 $\mu g/m^3$ was used.

Table 5-1. SO_2 Monitoring Site Used to Satisfy PSD Preconstruction Monitoring Requirements for the FPC DeBary Project

Site No.	Site Address	UTM Coordinates (km)			Relative Location from DeBary Facility[a]	
		Zone	North	East	Direction (Degrees)	Distance (km)
0930-001-F02	38 South Shell Road, DeBary, Volusia County	17	3,195.2	469.4	138	2.8

[a] UTM coordinates of DeBary facility are 600.9 km east and 4,229.5 km north.

Table 5-2. 1986 to 1989 SO_2 Monitoring Data for the Monitor Located in DeBary, Volusia County

			Measured Concentration ($\mu g/m^3$)				
			3-Hour		24-Hour		
Site No.	Year	Hours of Observation/Data Collection (%)	Highest	Second Highest	Highest	Second Highest	Annual
0930-001-F02	1986	8,386/95.7	76	75	24	23	4
	1987	8,249/94.2	66	61	40	39	5
	1988	8,425/95.9	100	90	28	25	4
	1989[a]	707/95.0	46	40	12	12	5

[a] Only January data available.

6.0 AIR QUALITY MODELING APPROACH

6.1 ANALYSIS APPROACH AND ASSUMPTIONS

6.1.1 GENERAL MODELING APPROACH

The general modeling approach followed EPA and FDER modeling guidelines for determining compliance with AAQS and PSD increments. In general, when model predictions are used to determine compliance with AAQS and PSD increments, current policies stipulate that the highest annual average and HSH short-term (i.e., 24 hours or less) concentrations be compared to the applicable standard when 5 years of meteorological data are used. The HSH concentration is calculated for a receptor field by:

1. Eliminating the highest concentration predicted at each receptor,
2. Identifying the second-highest concentration at each receptor, and
3. Selecting the highest concentration among these second-highest concentrations.

This approach is consistent with the air quality standards, which permit a short-term average concentration to be exceeded once per year at each receptor.

To develop the maximum short-term concentrations for the facility, the general modeling approach was divided into screening and refined phases to reduce the computation time required to perform the modeling analysis. The basic difference between the two phases is the receptor grid used when predicting concentrations.

Concentrations for the screening phase were predicted using a coarse receptor grid and a 5-year meteorological record. After a final list of maximum short-term concentrations was developed, the refined phase of the analysis was conducted by predicting concentrations for a refined receptor grid centered on the receptor at which the HSH concentration from the screening phase was produced. The air dispersion model was then executed for the entire year during which HSH concentrations were predicted. This approach was used to ensure that valid HSH concentrations were obtained.

More detailed descriptions of the emission inventory and receptor grids used in the screening and refined phases of the analysis are presented in the following sections.

6.1.2 MODEL SELECTION

The selection of the appropriate air dispersion model was based on its ability to simulate impacts in areas surrounding the DeBary Plant site. Within 50 km of the site, the terrain can be described as simple, i.e., flat to gently rolling. As defined in the EPA modeling guidelines, simple terrain is considered to be an area where the terrain features are all lower in elevation than the top of the stack(s) under evaluation. Therefore, a simple terrain model was selected to predict maximum ground-level concentrations.

The Industrial Source Complex (ISC) dispersion model (EPA, 1988a) was selected to evaluate the pollutant emissions from the proposed units and other modeled sources. This model is contained in EPA's User's Network for Applied Modeling of Air Pollution (UNAMAP), Version 6 (EPA, 1988b). The ISC model is applicable to sources located in either flat or rolling terrain where terrain heights do not exceed stack heights.

The ISC model consists of two sets of computer codes which are used to calculate short- and long-term ground level concentrations. The main differences between the two codes are the input format of the meteorological data and the method of estimating the plume's horizontal dispersion.

The first model code, the ISC short-term (ISCST) model, is an extended version of the single-source (CRSTER) model (EPA, 1977). The ISCST model is designed to calculate hourly concentrations based on hourly meteorological parameters (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The hourly concentrations are processed into non-overlapping, short-term and annual averaging periods. For example, a 24-hour average concentration is based on twenty-four 1-hour averages calculated from midnight to midnight of each day. For each short-term averaging period selected, the highest and second-highest average concentrations are calculated for each receptor. As an option, a table of the 50 highest concentrations over the entire field of receptors can be produced.

The second model code within the ISC model is the ISC long-term (ISCLT) model. The ISCLT model uses joint frequencies of wind direction, wind speed, and atmospheric stability to calculate seasonal and/or annual average ground-level concentrations. Because the input wind directions are for 16 sectors, with each sector defined as 22.5 degrees, the model calculates concentrations by assuming that the pollutant is uniformly distributed in the horizontal plane within a 22.5-degree sector.

In this analysis, the ISCST model was used to calculate both short-term and annual average concentrations because these concentrations are readily obtainable from the model output. Major features of the ISCST model are presented in Table 6-1. Concentrations due to stack and volume sources are calculated by the ISCST model using the steady-state Gaussian plume equation for a continuous source. The area source equation in the ISCST model is based on the equation for a continuous and finite crosswind line source. The ISC model has rural and urban options which affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground-level concentrations. The criteria used to determine when the rural or urban mode is appropriate are based on land use near the proposed plant's surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50 percent of the area within a 3-km radius circle centered on the proposed source, the urban option should be selected. Otherwise, the rural option is more appropriate.

Table 6-1. Major Features of the ISCST Model

ISCST Model Features

- Polar or Cartesian coordinate systems for receptor locations
- Rural or one of three urban options which affect wind speed profile exponent, dispersion rates, and mixing height calculations
- Plume rise due to momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975)
- Procedures suggested by Huber and Snyder (1976); Huber (1977); and Schulmann and Hanna (1986) and Schulmann and Scire (1980) for evaluating building wake effects
- Procedures suggested by Briggs (1974) for evaluating stack-tip downwash
- Separation of multiple point sources
- Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations
- Capability of simulating point, line, volume and area sources
- Capability to calculate dry deposition
- Variation with height of wind speed (wind speed-profile exponent law)
- Concentration estimates for 1-hour to annual average
- Terrain-adjustment procedures for elevated terrain including a terrain truncation algorithm
- Receptors located above local terrain, i.e., "flagpole" receptors
- Consideration of time-dependent exponential decay of pollutants
- The method of Pasquill (1976) to account for buoyancy-induced dispersion
- A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)
- Procedure for calm-wind processing

Source: EPA, 1988a.

For modeling analyses that will undergo regulatory review, such as PSD permit applications, the following model features are recommended by EPA (1987a) and are referred to as the regulatory options in the ISCST model:

1. Final plume rise at all receptor locations,
2. Stack-tip downwash,
3. Buoyancy-induced dispersion,
4. Default wind speed profile coefficients for rural or urban option,
5. Default vertical potential temperature gradients,
6. Calm wind processing, and
7. Reducing calculated SO_2 concentrations in urban areas by using a decay half-life of 4 hours (i.e., reduce the SO_2 concentration emitted by 50 percent for every 4 hours of plume travel time).

In this analysis, the EPA regulatory options were used to address maximum impacts. Based on a review of the land use around the facility and discussions with FDER, the rural mode was selected due to the lack of residential, industrial, and commercial development within 3 km of the DeBary Plant site.

6.2 METEOROLOGICAL DATA

Meteorological data used in the ISCST model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at Orlando International Airport and Ruskin, respectively. The 5-year period of meteorological data was from 1982 through 1986. The NWS station in Orlando, located approximately 45 km to the south of the site, was selected for use in the study because it is the closest primary weather station to the study area considered to have meteorological data representative of the project site. This station has surrounding topographical features similar to the project site and the most readily available and complete database.

The surface observations included wind direction, wind speed, temperature, cloud cover, and cloud ceiling height. The wind speed, cloud cover, and cloud ceiling values were used in the ISCST meteorological preprocessor program to determine atmospheric stability using the Turner stability scheme. Based on the temperature measurements at morning and afternoon, mixing heights were calculated from the radiosonde data at Ruskin using the Holzworth approach (Holzworth, 1972). The Ruskin station is located about 150 km to the southwest of the site. Hourly mixing heights were derived from the morning and afternoon mixing heights using the interpolation method developed by EPA (Holzworth, 1972). The hourly surface data and mixing heights were used to develop a sequential series of hourly meteorological data (i.e., wind direction, wind speed, temperature, stability, and mixing heights). Because the observed hourly wind directions at the NWS stations are classified into one of thirty-six 10-degree sectors, the wind directions were randomized within each sector to account for the expected variability in air flow. These calculations were performed using the EPA RAMMET meteorological preprocessor program.

6.3 EMISSION INVENTORY

Stack operating parameters and air emission rates for the proposed simple-cycle CTs were presented in Section 2.0. To determine the load that would produce the highest impacts, a modeling analysis was performed that predicted concentrations for the turbines operating at 25, 50, 75, and 100 percent of maximum capacity. For each load, the highest emissions and lowest flow rate were selected from the range of operational data that were dependent upon the temperature.

The existing sources consist of two boilers and six gas turbines. Stack parameters and maximum air emission rates for these sources were presented in Section 2.0.

Modeling of the proposed turbines demonstrated that the facility's impacts are above the significant impact levels for SO_2 at a distance greater than

50 km from the DeBary Plant site. Therefore, the emission inventories for SO_2 sources were developed from available databases.

FDER supplied KBN with printouts of the facilities within a 100 km square centered on the site (UTM coordinates: east 467.5 km, north 3,197.2). FDER also provided KBN with AIR 10 reports for Volusia and Orange counties. Using this information, supplemented with data from permits, PSD applications, and previous modeling analyses, the SO_2 emitting facilities within 50 km of the location of the site were identified.

Facilities located within 50 km of the DeBary Plant site with SO_2 emissions greater than 25 TPY are presented in Table 6-2. The facilities within 10 km of the DeBary Plant were included explicitly in the modeling analysis. Facilities located within 10 to 40 km of the Debary Plant with SO_2 emissions greater than 200 TPY and facilities located within 40 to 50 km of the plant with SO_2 emissions greater than 400 TPY also were modeled explicitly.

The stack, operating, and emission data for those sources considered in the modeling are presented in Table 6-3. PSD increment-affecting sources are noted and were used in the PSD modeling analysis.

6.4 RECEPTOR LOCATIONS

As discussed in Section 6.1, the general modeling approach considered screening and refined phases to address compliance with maximum allowable PSD Class II increments and AAQS. In the ISCST modeling, concentrations were predicted for the screening phase using several receptor grids. The locations of the receptors were based on identifying the areas in which maximum concentrations are predicted due to the proposed units.

A description of the receptor locations for determining compliance with PSD increments and AAQS is as follows:

1. 567 receptors located in a radial grid centered on the proposed units. These receptors were classified into two main groups:

Table 6-2. SO_2 Sources (>25 TPY) Within 50 km of the FPC DeBary Facility

Distance Category	APIS Facility Identification Number	Facility	County	UTM Coordinates (km)		Relative Location Relative Location to FPC DeBary Facility[a]				Maximum Allowable SO_2 Emissions (TPY)
				East	North	X (km)	Y (km)	Distance (km)	Direction (degrees)	
0-10 km	30ORL640064	Martin Asphalt	Volusia	467.9	3193.1	0.4	-4.1	4.1	174	536
	30ORL640028	FPL--Sanford	Volusia	468.3	3190.4	0.8	-6.8	6.8	173	46,976
	30ORL640020	FPC--Turner	Volusia	473.4	3193.3	5.9	-3.9	7.1	123	29,287
	30ORL590033	C A Meyer Paving and Constr.	Seminole	469.5	3189.0	2.0	-8.2	8.5	166	80
10-30 km	30ORL590007	L D Plante	Seminole	474.5	3176.2	7.0	-21.0	22.1	162	34
30-50 km	30ORG480068	Zellwood Farms	Orange	440.8	3180.0	-26.7	-17.2	31.8	237	101
	30ORG480156	Rogers Group, Inc.	Orange	455.8	3167.1	-11.7	-30.1	32.3	201	164
	30ORG480088	Ralston Purina Co.	Orange	451.1	3167.7	-16.4	-29.5	33.8	209	54
	30ORG350004	Florida Food Products	Lake	431.5	3194.1	-36.0	-3.1	36.1	265	97
	30ORG480063	Florida Hospital	Orange	463.8	3160.7	-3.7	-36.5	36.7	186	36
	30ORL640043	Martin Asphalt Co.	Volusia	496.7	3224.5	29.2	27.1	39.8	47	50
	30ORG480014	FPC--Rio Pinar	Orange	475.2	3156.8	7.7	-40.4	41.1	169	109
	30ORG480097	National Linen Service	Orange	462.2	3155.6	-5.3	-41.6	41.9	187	355
	30ORL640003	New Smyrna Beach Utilities	Volusia	505.9	3215.0	38.4	17.8	42.2	65	3,826
	30ORG480138	AT&T Technologies, Inc.	Orange	459.3	3153.6	-8.2	-43.6	44.4	191	64
	30ORG480053	Winter Garden Citrus Corp.	Orange	443.8	3159.6	-23.7	-37.6	44.4	212	145
	30ORG480048	American Asphalt Inc.	Orange	444.8	3158.2	-22.7	-39.0	45.1	210	53
	30ORG480137	OUC--Stanton Energy Center	Orange	483.5	3150.6	16.0	-46.6	49.3	161	41,304

Note: km = kilometers.
TPY = tons per year.

[a] The UTM coordinates of the FPC DeBary Plant are 467.5 km east and 3197.2 km north.

Table 6-3. Summary of SO_2 Emission Sources Used in the Modeling Analysis

Model. ID No.	Source Name	Emissions		Height		Velocity		Temperature		Diameter	
		lb/hr	(g/s)	ft	(m)	fps	(mps)	°F	(K)	ft	(m)
9003	FPL Sanford Unit #3	1,815	228.7	300	91.4	113	34.4	275	408	9.51	2.90
9045	FPL Sanford Units #4,5	8,910	1,122.7	392	119.5	73.4	22.4	313	429	19.2	5.84
20002	FPC Turner Unit #2	990	124.7	237	72.3	58	17.7	260	400	6.0	1.83
20003	FPC Turner #3	2,255	284.1	237	72.3	79	24.1	315	430	6.0	1.83
20004	FPC Turner #4	2,255	284.1	237	72.3	76	23.2	270	405	6.4	1.95
20012	FPC Turner GT Units 1&2	329	40.6	39	11.9	63	19.2	960	789	12.9	3.93
20034	FPC Turner GT Units 1&2	867	109.0	35	10.7	100	30.5	900	755	19.1	5.82
99937	OUC Stanton Energy Center	9,430	1188.2	550	167.6	83	25.3	127	326	19.0	5.79
33001	C.A.Meyer Paving	41	5.2	34	10.4	103	31.4	325	436	3.2	0.98
99903	New Smyrna Beach Utilities[a]	873.5	110.1	29	8.8	78	23.8	650	616	2.2	0.67
64001	Martin Asphalt	122.3	15.4	20	6.1	90	27.4	325	436	3.1	0.94

[a] PSD increment-consuming source.

   a. Plant boundary and near-field receptors, and
   b. General grid receptors.

2. The grid for the plant boundary receptors consisted of 36 receptors. The near-field grid consisted of 27 receptors located 300 m from the proposed stack, off of plant property. These receptors are presented in Table 6-4.
3. The general grid receptors consisted of 504 receptors located at distances of 500; 800; 1,200; 1,600; 2,000; 2,500; 3,000; 3,500; 4,000; 4,500; 5,000; 6,000; 7,000; and 8,000 m along 36 radials with each radial spaced at 10-degree increments.

After the screening modeling was completed, refined short-term modeling was conducted using a receptor grid centered on the receptor which had the highest, second-highest short-term concentrations from the screening analysis. The receptors were located at intervals of 100 m between the distances considered in the screening phase, along 9 radials spaced at 2-degree increments, centered on the radial along which the maximum concentration was produced. For example, if the maximum concentration was produced along the 90-degree radial at a distance of 1.6 km, the refined receptor grid would consist of receptors at the following locations:

Directions (degrees)	Distance (km)
82, 84, 86, 88, 90, 92, 94, 96, 98	1.3, 1.4, 1.5, 1.6, 1.7, 1.8, and 1.9 per direction

To ensure that a valid HSH concentration was calculated, concentrations were predicted using the refined grid for the entire year that produced the HSH concentrations from the screening receptor grid.

Refined modeling analysis was not performed for the annual averaging period, because the spatial distribution of annual average concentrations are not expected to vary significantly from those produced from the screening analysis.

Table 6-4. Plant Property Receptors Used in the Screening Analysis

Direction (degrees)	Distance (m)	Direction (degrees)	Distance (m)
10	448	190	103 and 300
20	492	200	108 and 300
30	492	210	113 and 300
40	445	220	124 and 300
50	382	230	120 and 300
60	347	240	108 and 300
70	324	250	101 and 300
80	103 and 300	260	98 and 300
90	103 and 300	270	98 and 300
100	103 and 300	280	98 and 300
110	108 and 300	290	101 and 300
120	115 and 300	300	108 and 300
130	129 and 300	310	117 and 300
140	124 and 300	320	136 and 300
150	113 and 300	330	164 and 300
160	108 and 300	340	225 and 300
170	103 and 300	350	385
180	103 and 300	360	448

Note: Direction and distance are relative to center point of stacks for proposed units.

6.5 BACKGROUND CONCENTRATIONS

Background concentrations used in the air quality impact analysis are discussed in Section 5.0. The SO_2 background concentrations used in the AAQS analysis were 90 $\mu g/m^3$, 25 $\mu g/m^3$ and 4 $\mu g/m^3$ for averaging times of 3-hour, 24-hour and annual, respectively.

6.6 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with buildings and structures planned at the DeBary Plant, the stacks for the proposed turbines will be less than GEP. In addition, the stacks for the existing boilers and turbines are below GEP height based upon the existing boiler and turbine buildings and structures. Therefore, the potential for building downwash to occur was considered in the modeling analysis.

The procedures used for addressing the effects of building downwash are those recommended in the ISC Dispersion Model User's Guide. The building height, length, and width are input to the model, which uses these parameters to modify the dispersion parameters. For short stacks (i.e., physical stack height is less than H_b + 0.5 L_b, where H_b is the building height and L_b is the lesser of the building height or projected width), the Schulman and Scire (1980) method is used. If this method is used, then direction-specific building dimensions are input for H_b and L_b for 36 radial directions, with each direction representing a 10 degree sector. The features of the Schulman and Scire method are: 1) reduced plume rise due to initial plume dilution, 2) enhanced plume spread as a linear function of the effective plume height, and 3) specification of building dimensions as a function of wind direction.

For cases where the physical stack is greater than H_b + 0.5 L_b but less than GEP, the Huber-Snyder (1976) method is used. For this method, the ISCST model calculates the area of the building using the length and width, assumes the area is representative of a circle, and then calculates a building width by determining the diameter of the circle. If a specific width is to be modeled, then the value input to the model must be adjusted according to the following formula:

$$M_w = \frac{\pi W^2}{4}$$

$$M_w = 0.8886\ W$$

where: M_w is input to the model to produce a building width of W used in the dispersion calculation. W is the actual building width.

The building dimensions considered in the modeling analysis are presented in Table 6-5. In the case of the existing boilers, the boiler stacks are located on the existing boiler buildings and are affected by downwash for all directions.

Table 6-5. Building Dimensions Used in ISCST Modeling Analysis To Address Potential Building Wake Effects

Source	Associated Building	Actual Building Dimensions (m)			Projected Width[a] (m)	Modeled Building Dimensions (m)	
		Length	Width	Height		Length, Width	Height
FPC--Existing Turbines No. 1 to No. 6	Turbine Structure	18.6	8.4	8.84	20.4	20.4	8.84
FPC--Existing Boilers No. 1 and 2	Boiler Building	27.4	10.7	5.49	29.4	29.4	5.49
FPC--Proposed CTs	Proposed Structure	18.0	7.1	11.8	19.3	19.3	11.8
FPL Sanford, Unit 3	Boiler Buildings No. 4 and 5	101.2	25.9	47.9	104.5	104.5	47.9

[a] Diagonal of actual building dimensions.

7.0 AIR QUALITY MODELING RESULTS

7.1 PROPOSED UNITS ONLY

A summary of the maximum concentrations due to the proposed CT units operating at load conditions of 100, 75, 50, and 25 percent of capacity is presented in Table 7-1. The results are presented for SO_2 concentrations and it is assumed that the stacks are colocated. The stacks were modeled at separate locations in subsequent analyses that addressed compliance with PSD increments and AAQS. Also, for operating load, the modeling was performed using the highest emissions at 20°F design condition coupled with the lowest exit gas flow rates at 95°F design condition to maximize predicted impacts. As shown in Table 7-1, the maximum concentrations generally occur for the maximum capacity at 100-percent operating load. Therefore, the proposed units were modeled at this load condition in the PSD increment and AAQS modeling analyses. A summary of the maximum predicted impacts of regulated pollutants due to the proposed units only, based on the results in Table 7-1, is presented in Table 7-2.

The maximum predicted 3-hour, 24-hour, and annual SO_2 concentrations due to the proposed CT units only are 50.9, 11.4, and 0.94 $\mu g/m^3$, respectively. The maximum 3-hour and 24-hour impacts are above the significance levels established by EPA and FDER and, therefore, further modeling analysis is required for SO_2 to demonstrate compliance with PSD increments and AAQS.

The maximum predicted 24-hour and annual average PM(TSP) concentrations due to the units only are 1.2 and 0.10 $\mu g/m^3$, respectively. Maximum PM10 impacts are assumed to be identical to the PM(TSP) impacts. Since these maximum concentrations are below the significance levels for these pollutants, no further modeling analysis is necessary.

The maximum predicted annual NO_2 concentration due to the units only is 0.31 $\mu g/m^3$. Because this level of impact is below the significance level, no further modeling analysis was performed.

Table 7-1. Maximum SO_2 Concentrations Predicted for Proposed CTs Only at Various Operating Load Conditions

Averaging Period/ Year	Maximum Concentration ($\mu g/m^3$) for Operating Load (percent) 100	75	50	25
1-Hour[a]				
1982	133	100	101	72.5
1983	133	114	100	87.4
1984	139	107	93.5	68.2
1985	135	106	100	70.5
1986	138	122	93.9	67.3
3-Hour[a]				
1982	44.3	41.2	38.4	33.5
1983	46.6	43.0	34.5	31.2
1984	50.9	42.1	35.7	33.3
1985	47.1	45.6	36.7	28.5
1986	59.2	44.0	36.0	30.3
8-Hour[a]				
1982	20.6	20.5	19.7	16.8
1983	29.9	21.8	21.5	19.1
1984	27.4	23.9	19.8	15.9
1985	23.9	22.1	19.5	15.9
1986	22.2	20.3	18.8	16.7
24-Hour[a]				
1982	9.62	9.78	9.27	8.08
1983	9.99	8.71	8.01	7.06
1984	11.4	8.66	8.75	7.86
1985	10.6	9.10	9.63	8.00
1986	9.36	8.48	7.92	8.48
Annual				
1982	0.82	0.80	0.82	0.76
1983	0.69	0.71	0.70	0.64
1984	0.94	0.96	0.95	0.87
1985	0.80	0.82	0.80	0.72
1986	0.79	0.80	0.79	0.70

Note: These results are based on the colocation of each stack. Each of the stacks were at separate locations in subsequent modeling for the PSD and AAQS analyses.

[a] Highest, second-highest concentrations.

Table 7-2. Summary of Maximum Pollutant Concentrations Due to the Proposed Project

Pollutant	Averaging Period	Maximum Predicted Concentrations ($\mu g/m^3$)[a]	Location		Significance Impact Level ($\mu g/m^3$)	*De Minimis* Monitoring Level ($\mu g/m^3$)
			Direction (°)	Distance (km)		
Sulfur Dioxide	3-hour	50.9	60	1.6	25	NA
	24-hour	11.4	120	1.6	5	13
	Annual	0.94	240	5.0	1	NA
Total Suspended Particulate Matter	24-hour	1.2	120	1.6	5	10
	Annual	0.10	240	5.0	1	NA
Particulate Matter 10 microns	24-hour	1.2	120	1.6	5	10
	Annual	0.10	240	5.0	1	NA
Nitrogen Dioxide	Annual	0.31	240	5.0	1	14
Carbon Monoxide	1-hour	13.3	60	1.6	2,000	NA
	8-hour	2.9	240	1.6	500	575
Beryllium	24-hour	0.000053	120	1.6	NA	0.25
Mercury	24-hour	0.000063	120	1.6	NA	0.25

Note: NA = Not applicable.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Based upon six CTs operating at maximum load.

[b] Not modeled because predicted concentrations due to the proposed units only were less than significance level.

The maximum predicted 1- and 8-hour average CO concentrations due to the units only are 13.3 and 2.9 $\mu g/m^3$, respectively. These maximum impacts are less than the CO significance impact levels. Because the maximum predicted impacts due to the repowered units are less than the CO significance levels, additional modeling is not required for this pollutant.

The maximum 24-hour Be concentration due to the units only is predicted to be 0.000053 $\mu g/m^3$. No significance level has been established for F, but a de minimis monitoring concentration has been set at 0.25 $\mu g/m^3$, 24-hour average. Since the predicted impacts due to the units only are well below the de minimis, no further modeling analysis was conducted.

The maximum predicted 24-hour Hg concentration due to the proposed units only is 0.000063 $\mu g/m^3$. Similar to the Be analysis, no significance level has been established for Hg, but a de minimis monitoring concentration has been set at 0.25 $\mu g/m^3$, 24-hour average. Since the predicted impacts due to the units only are well below the de minimis level, no further modeling analysis was conducted.

7.2 PSD CLASS II INCREMENT ANALYSIS

Maximum SO_2 concentrations predicted from the screening analysis for comparison to the PSD Class II increments are presented in Table 7-3. Based upon these results, the refined analysis was based on modeling the year during which the overall highest, second-highest 3-hour and 24-hour SO_2 concentrations were predicted in the screening analysis. The refined analysis for the annual average SO_2 concentrations was based on modeling the receptor and year which produced the highest annual concentration using the refined emission inventory. A summary of the maximum SO_2 PSD Class II increment consumption concentrations predicted in the refined analysis is presented in Table 7-4.

The maximum 3-hour average SO_2 PSD increment consumption from the refined analysis is predicted to be 138 $\mu g/m^3$, which is 27 percent of the maximum

Table 7-3. Maximum Predicted SO_2 Concentrations from the Screening Analysis for Comparison to PSD Class II Increments

		Receptor Location[a]		Period		
Averaging Period	Maximum Concentration ($\mu g/m^3$)	Direction (°)	Distance (km)	Julian Day	Hour Ending	Year
3-Hour[b]	85	60	6.0	365	6	1982
	104	100	8.0	212	24	1983
	129	110	8.0	339	24	1984
	123	80	8.0	236	6	1985
	111	50	8.0	17	24	1986
24-Hour[b]	16.3	320	8.0	332	–	1982
	15.3	70	6.0	322	–	1983
	22.4	280	4.0	133	–	1984
	21.7	90	6.0	206	–	1985
	20.5	360	3.0	110	–	1986
Annual	2.25	180	8.0	–	–	1982
	2.06	110	7.0	–	–	1983
	2.33	110	6.0	–	–	1984
	2.53	110	7.0	–	–	1985
	2.52	360	7.0	–	–	1986

Note: Based on six CTs operating at maximum load and firing fuel oil with 0.5 percent sulfur content.

– = Not applicable.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Relative to the location of the proposed CT units.
[b] Highest, second-highest concentrations predicted for this averaging period.

Table 7-4. Maximum Predicted SO_2 Concentrations from the Refined Analysis for Comparison to PSD Class II Increments

Averaging Period	Maximum Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (°)	Distance (km)	Period Julian Day	Hour Ending	Year	PSD Class II Increment
SO_2 Concentrations							
3-Hour[b]	138	104	8.9	339	24	1984	512
24-Hour[b]	23.2	278	3.8	242	24	1984	91
Annual	2.53	110	7.0	—	—	1985	20

Note: Based on six CTs operating at maximum load and firing fuel oil with 0.5 percent sulfur content.

— = Not applicable.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Relative to the location of the proposed CT units.
[b] Highest, second-highest concentrations predicted for this averaging period.

allowable PSD Class II increment of 512 μg/m^3, not to be exceeded more than once per year.

The maximum 24-hour average SO_2 PSD Class II increment consumption is predicted to be 23.2 μg/m^3, which is 25 percent of the maximum allowable PSD Class II increment of 91 μg/m^3, not to be exceeded more than once per year.

The maximum annual average SO_2 PSD increment consumption is predicted to be 2.53 μg/m^3, which is 13 percent of the maximum allowable PSD Class II increment of 20 μg/m^3.

7.3 AAQS ANALYSIS

The maximum 3-hour, 24-hour, and annual average total SO_2 concentrations predicted from the screening analysis are presented in Table 7-5. The total concentrations were determined from the impacts of the modeled sources added to the background concentration (refer to Section 5.0). These results show that the maximum SO_2 concentrations due to all sources are below the AAQS for all averaging periods.

Similar to the PSD Class II increment analysis, the refined AAQS analysis was based on modeling the year during which the overall HSH 3-hour, 24-hour, and highest annual concentrations were predicted in the screening analysis. The maximum SO_2 concentrations predicted in the refined analysis are presented in Table 7-6.

The maximum 3-hour average SO_2 concentration due to all sources from the refined analysis is predicted to be 792 μg/m^3, which is 61 percent of the AAQS of 1,300 μg/m^3, not to be exceeded more than once per year. The project contributed 0 percent of this maximum 3-hour average concentration.

Table 7-5. Maximum Predicted Total SO_2 Concentrations from the Screening Analysis for Comparison to AAQS

	Concentration ($\mu g/m^3$)			Receptor Location[a]		Period		
		Total Due To						
Averaging Period	Total	Modeled Sources	Background	Direction (°)	Distance (km)	Julian Day	Hour Ending	Year
3-Hour[b]	732	642	90	130	6.0	194	12	1982
	727	637	90	130	8.0	49	12	1983
	698	608	90	120	8.0	109	15	1984
	624	534	90	110	7.0	170	12	1985
	680	590	90	130	6.0	268	15	1986
24-Hour[b]	212	187	25	350	0.385	33	–	1982
	214	189	25	360	0.448	97	–	1983
	194	169	25	340	0.225	280	–	1984
	238	213	25	350	0.385	243	–	1985
	214	189	25	330	0.500	68	–	1986
Annual	37.7	33.7	4	340	0.225	–	–	1982
	33.8	29.8	4	340	0.225	–	–	1983
	37.4	33.4	4	340	0.225	–	–	1984
	34.6	30.6	4	340	0.225	–	–	1985
	31.6	27.6	4	340	0.225	–	–	1986

Note: Based on six CTs operating at maximum load and firing fuel oil with 0.5 percent sulfur content.

– = Not applicable.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Relative to the location of the proposed CT units.
[b] Highest, second-highest concentrations predicted for this averaging period.

Table 7-6. Maximum Predicted SO_2 Concentrations from the Refined Analysis for Comparison to AAQS

	Concentration ($\mu g/m^3$)			Receptor Location[a]		Period			
		Total due to							
Averaging Period	Total	Modeled Sources	Background	Direction (°)	Distance (km)	Julian Day	Hour Ending	Year	AAQS
SO_2 Concentrations									
3-Hour[b]	792	702	90	130	6.2	197	15	1982	1,300
24-Hour[b]	215	190	25	354	0.450	325	24	1985	260
Annual	37.7	33.7	4	340	0.225	–	–	1982	60

Note: Based on six CTs operating at maximum load and firing fuel oil with 0.5 percent sulfur content.

– = Not applicable.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Relative to the location of the proposed CT units.
[b] Highest, second-highest concentrations predicted for this averaging period.

The maximum 24-hour average SO_2 concentration due to all sources is predicted to be 215 $\mu g/m^3$, which is 83 percent of the AAQS of 260 $\mu g/m^3$, not to be exceeded more than once per year. The project contributed less than 1 percent of this maximum 24-hour average concentration.

The maximum annual average SO_2 concentration due to all sources is predicted to be 37.7 $\mu g/m^3$, which is 63 percent of the AAQS of 60 $\mu g/m^3$. The project contributed less than 1 percent to the maximum concentration.

8.0 ADDITIONAL IMPACT ANALYSIS

8.1 IMPACTS UPON VEGETATION

The response of vegetation to atmospheric pollutants is influenced by the concentration of the pollutant, duration of the exposure and the frequency of exposures. The pattern of pollutant exposure expected from the facility is that of a few episodes of relatively high ground-level concentration which occur during certain meteorological conditions interspersed with long periods of extremely low ground-level concentrations. If there are any effects of stack emissions on plants, they will be from the short-term higher doses. A dose is the product of the concentration of the pollutant and the duration of the exposure. The impact of the proposed CT units on regional vegetation was assessed by comparing pollutant doses that are predicted from modeling with threshold doses reported from the scientific literature which could adversely affect plant species typical of those present in the region.

8.1.1 SULFUR DIOXIDE

The maximum total 3-hour average SO_2 concentration (i.e., impacts due to all modeled sources added to a background concentration) is predicted to be 702 $\mu g/m^3$ (see Table 7-6). This concentration is predicted to occur about 6.2 km southeast of the stacks and represents the concentration that would occur during the worst-case meteorological conditions of the past five years. The maximum 3-hour average ground-level concentration predicted for the other 4 years are 90 percent or less of the maximum concentration. Concentrations decrease with distance beyond the location of the maximum concentration.

The maximum total predicted 24-hour average SO_2 concentration is 190 $\mu g/m^3$ (see Table 7-6) and is located approximately 0.45 km to the north of the stacks. The maximum total predicated annual SO_2 concentration is 33.7 $\mu g/m^3$ (see Table 7-6). This concentration is predicted to occur 0.225 km to the north-northwest of the stacks.

These concentrations and averaging times can be compared with SO_2 doses known to adversely affect plant species (see Table 8-1). The expected doses from the proposed project combined with background sources are much lower than doses known to cause a detrimental effect on vegetation.

8.1.2 OTHER POLLUTANTS

Predicted impacts of other regulated pollutants are less than the significant impact levels (see Table 7-2). As a result, no impacts are expected to occur to vegetation as a result of the proposed emissions of other regulated pollutants.

8.2 IMPACTS TO SOILS

SO_2 that reaches the soil by deposition from the air is converted by physical and biotic processes to sulfates. (Particulates have no affect on soils at the levels predicted.) The effects can be beneficial to plants if sulfates in native soils are less than plant requirements for optimum growth. However, sulfates can also increase acidity of unbuffered soils, causing adverse effects due to changes in nutrient availability and cycling. The predicted concentrations of SO_2 from stack emissions are not expected to have a significant adverse effect on soils in the vicinity because:

1. The predicted concentrations are low; and
2. Fertilizer and ground limestone is generally applied to lands being used for crops, pasture, and citrus.

Therefore, the facility is not expected to have a significant adverse impact on regional vegetation or soils.

8.3 IMPACTS DUE TO ADDITIONAL GROWTH

A limited number of additional personnel may be added to the current plant personnel complement. These additional personnel are expected to have an insignificant effect on the residential, commercial, and industrial growth in Volusia County.

Table 8-1. Sulfur Dioxide Doses Reported to Affect Plant Species Similar to Vegetation in the Region of the DeBary Plant

Species	Dose and Effect	Reference
Strawberry	1,040 $\mu g/m^3$ for 6 hours per day for 3 days had no affect on growth	Rajput _et al_., 1977
Citrus	2,080 $\mu g/m^3$ for 23 days with 10 day interruption reduced leaf area	Matsushima and Brewer, 1972
Ryegrass	42 $\mu g/m^3$ for 26 weeks or 367 $\mu g/m^3$ for 131 days reduced dry weight	Bell _et al_., 1979; Ayazaloo and Bell, 1981
Tomato	1,258 $\mu g/m^3$ for 5 hours per day, for 57 days, reduced growth	Kohut _et al_., 1983
Duckweed	390 $\mu g/m^3$ for 6 weeks reduced growth	Fankhauser _et al_., 1976
Lichens (_Parmotrema_ and _Ramalina_ spp.)	400 $\mu g/m^3$ 6 hours per week for 10 weeks reduced CO_2 uptake and biomass gain of _Ramalina_, not _Parmotrema_	Hart _et al_., 1988
Bald Cypress	1,300 and 2,600 $\mu g/m^3$ for 48 hours. Only 2,600 $\mu g/m^3$ reduced leaf area.	Shanklin and Kozlowski, 1985
Green Ash	210 $\mu g/m^3$ for 4 hours per day, 5 days per week for 6 weeks reduced growth	Chappelka _et al_., 1988

Fuel oil will be delivered by truck to the facility in the same manner as residual oil. The rail line will be activated for delivery of additional fuel oil. No additional significant impacts are expected to occur because of these activities.

Therefore, no air quality related impacts associated with residential, commercial, and industrial growth are anticipated.

8.4 IMPACTS TO VISIBILITY

The DeBary Plant is located more than 100 km from a Class I area; pursuant to Chapter 17-2.500(5)(d)1.e., F.A.C., a visibility impact analysis is not required.

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APPENDIX A

DESIGN INFORMATION OF OPERATING, STACK, AND POLLUTANT EMISSION DATA FOR THE PROPOSED COMBUSTION TURBINES

Table A-1. Design Information and Stack Parameters for Florida Power Corporation DeBary CT Project (CT Performance Data For Fuel Oil at Peak Load[a])

Data	GE PG 7111EA No.2 Oil at 20°F	GE PG 7111EA No.2 Oil at 59°F	GE PG 7111EA No.2 Oil at 90°F
General			
Power (kW)	104,890.0	92,890.0	82,740.0
Heat Rate (Btu/kWh)	10,910.0	11,080.0	11,260.0
Heat Input (10^6 Btu/hr)	1,144.3	1,029.2	931.7
Fuel Oil (lb/hr)	61,690.0	55,483.6	50,223.8
Fuel			
Heat Content--Oil(LHV)	18,550.0	18,550.0	18,550.0
Percent Sulfur	0.5	0.5	0.5
CT Exhaust			
Volume Flow (acfm)	1,662,283	1,551,317	1,455,469
Volume Flow (scfm)	594,638	544,974	503,926
Mass Flow (lb/hr)	2,633,000	2,408,000	2,218,000
Temperature (°F)	1,016	1,043	1,065
Moisture (% vol)	9.16	9.60	10.66
Moisture (% mass)	5.80	6.09	6.79
Oxygen (% vol)	12.29	12.33	12.25
Oxygen (% mass)	13.83	13.90	13.87
Molecular Weight	28.44	28.38	28.27
Water Injected (lb/hr)	64,190	55,510	43,130
Diameter (ft)	13.8	13.8	13.8
Velocity (ft/sec)	184.4	172.1	161.5

Note: Data from GE combustion turbine performance and emission guarantees.

[a] Represents maximum fuel usage, electrical output, and emission condition; base load values are slightly lower than those presented herein.

Table A-2. Maximum Criteria Pollutant Emissions for Florida Power Corporation DeBary CT Project (Fuel Oil at Peak Load)

Pollutant	GE PG 7111EA No.2 Oil at 20°F	GE PG 7111EA No.2 Oil at 59°F	GE PG 7111EA No.2 Oil at 90°F
Particulate			
Basis	15 lb/hr	15 lb/hr	15 lb/hr
lb/hr	15.0	15.0	15.0
TPY	65.7	65.7	65.7
Sulfur Dioxide			
Basis	0.5% Sulfur	0.5% Sulfur	0.5% Sulfur
lb/hr	616.90	554.84	502.24
TPY	2,702.0	2,430.2	2,199.8
Nitrogen Oxides			
Basis (Thermal NO_x)	42 ppm[a]	42 ppm[a]	42 ppm[a]
lb/hr	202.9	182.4	164.9
TPY	888.8	799.0	722.2
ppm[b]	42.0	42.0	42.0
Carbon Monoxide			
Basis	25 ppm[c]	25 ppm[c]	25 ppm[c]
lb/hr	58.9	53.7	49.1
TPY	257.8	235.2	214.9
ppm	25.0	25.0	25.0
VOCs			
Basis	5.0 lb/hr	5.0 lb/hr	4.5 lb/hr
lb/hr	5.00	5.00	4.50
TPY	21.9	21.9	19.7
Lead			
Basis	EPA(1988)	EPA(1988)	EPA(1988)
lb/hr	1.02×10^{-2}	9.16×10^{-3}	8.29×10^{-3}
TPY	4.46×10^{-2}	4.01×10^{-2}	3.63×10^{-2}

[a] Corrected to 15% O_2 dry conditions; GE guarantee.

[b] Does not include an allowance of fuel-bound nitrogen of 0.015 percent or greater.

[c] Corrected to dry conditions; GE guarantee.

Table A-3. Maximum Other Regulated Pollutant Emissions for Florida Power Corporation DeBary CT Project (Fuel Oil at Peak Load)

Pollutant	GE PG 7111EA No.2 Oil at 20°F	GE PG 7111EA No.2 Oil at 59°F	GE PG 7111EA No.2 Oil at 90°F
Arsenic			
lb/hr	$4.81\mathrm{x}10^{-3}$	$4.32\mathrm{x}10^{-3}$	$3.91\mathrm{x}10^{-3}$
TPY	$2.11\mathrm{x}10^{-2}$	$1.89\mathrm{x}10^{-2}$	$1.71\mathrm{x}10^{-2}$
Beryllium			
lb/hr	$2.86\mathrm{x}10^{-3}$	$2.57\mathrm{x}10^{-3}$	$2.33\mathrm{x}10^{-3}$
TPY	$1.25\mathrm{x}10^{-2}$	$1.13\mathrm{x}10^{-2}$	$1.02\mathrm{x}10^{-2}$
Mercury			
lb/hr	$3.43\mathrm{x}10^{-3}$	$3.09\mathrm{x}10^{-3}$	$2.79\mathrm{x}10^{-3}$
TPY	$1.50\mathrm{x}10^{-2}$	$1.35\mathrm{x}10^{-2}$	$1.22\mathrm{x}10^{-2}$
Fluorine			
lb/hr	$3.72\mathrm{x}10^{-2}$	$3.34\mathrm{x}10^{-2}$	$3.03\mathrm{x}10^{-2}$
TPY	$1.63\mathrm{x}10^{-1}$	$1.47\mathrm{x}10^{-1}$	$1.33\mathrm{x}10^{-1}$
Sulfuric acid			
lb/hr	76.8	69.1	62.5
TPY	336.5	302.6	273.9

Sources: EPA, 1988; EPA, 1980.

Table A-4. Maximum Nonregulated Pollutant Emissions for Florida Power Corporation DeBary CT Project (Fuel Oil at Peak Load)

Pollutant	Gas Turbine No.2 Oil at 40°F	Gas Turbine No.2 Oil at 59°F	Gas Turbine No.2 Oil at 90°F
Manganese			
lb/hr	7.37×10^{-3}	6.63×10^{-3}	6.00×10^{-3}
TPY	3.23×10^{-2}	2.90×10^{-2}	2.63×10^{-2}
Nickel			
lb/hr	1.95×10^{-1}	1.75×10^{-1}	1.58×10^{-1}
TPY	8.52×10^{-1}	7.66×10^{-1}	6.94×10^{-1}
Cadmium			
lb/hr	1.20×10^{-2}	1.08×10^{-2}	9.78×10^{-3}
TPY	5.26×10^{-2}	4.73×10^{-2}	4.28×10^{-2}
Chromium			
lb/hr	5.44×10^{-2}	4.89×10^{-2}	4.43×10^{-2}
TPY	2.38×10^{-1}	2.14×10^{-1}	1.94×10^{-1}
Copper			
lb/hr	3.20×10^{-1}	2.88×10^{-1}	2.61×10^{-1}
TPY	1.40	1.26	1.14
Vanadium			
lb/hr	7.98×10^{-2}	7.18×10^{-2}	6.50×10^{-2}
TPY	3.49×10^{-1}	3.14×10^{-1}	2.85×10^{-1}
Selenium			
lb/hr	2.69×10^{-2}	2.42×10^{-2}	2.19×10^{-2}
TPY	1.18×10^{-1}	1.06×10^{-1}	9.58×10^{-2}
Polycyclic Organic Matter			
lb/hr	3.19×10^{-4}	2.87×10^{-4}	2.60×10^{-4}
TPY	1.40×10^{-3}	1.26×10^{-3}	1.14×10^{-3}
Formaldehyde			
lb/hr	4.63×10^{-1}	4.17×10^{-1}	3.77×10^{-1}
TPY	2.03	1.83	1.65

Source: EPA, 1988.

Table A-5. Maximum Emissions for Additional Nonregulated Pollutants for Florida Power Corporation DeBary CT Project (Fuel Oil at Peak Load)

Pollutant	Gas Turbine No.2 Oil at 40°F	Gas Turbine No.2 Oil at 59°F	Gas Turbine No.2 Oil at 90°F
Antimony			
lb/hr	2.50×10^{-2}	2.25×10^{-2}	2.04×10^{-2}
TPY	1.09×10^{-1}	9.85×10^{-2}	8.91×10^{-2}
Barium			
lb/hr	2.23×10^{-2}	2.01×10^{-2}	1.82×10^{-2}
TPY	9.78×10^{-2}	8.80×10^{-2}	7.97×10^{-2}
Colbalt			
lb/hr	1.04×10^{-2}	9.33×10^{-3}	8.44×10^{-3}
TPY	4.54×10^{-2}	4.09×10^{-2}	3.70×10^{-2}
Zinc			
lb/hr	7.82×10^{-1}	7.03×10^{-1}	6.37×10^{-1}
TPY	3.42	3.08	2.79
Chlorine[a]			
lb/hr	3.08×10^{-2}	2.77×10^{-2}	2.51×10^{-2}
TPY	1.35×10^{-1}	1.22×10^{-1}	1.10×10^{-1}

[a] Assumes 0.5 ppm in fuel oil.

Source: EPA, 1979.

Table A-6. Design Information and Stack Parameters for Florida Power Corporation DeBary CT Project (CT Performance Data For Fuel Oil at 75% Load)

Data	GE PG 7111EA No.2 Oil at 20°F	GE PG 7111EA No.2 Oil at 59°F	GE PG 7111EA No.2 Oil at 90°F
<u>General</u>			
Power (kW)	72,580.0	64,010.0	56,700.0
Heat Rate (Btu/kWh)	11,110.0	11,450.0	11,820.0
Heat Input (10^6 Btu/hr)	806.4	732.9	670.2
Fuel Oil (lb/hr)	43,469.7	39,510.2	36,129.1
<u>Fuel</u>			
Heat Content--Oil(LHV)	18,550.0	18,550.0	18,550.0
Percent Sulfur	0.5	0.5	0.5
<u>CT Exhaust</u>			
Volume Flow (acfm)	1,356,805	1,282,418	1,220,251
Volume Flow (scfm)	579,606	532,324	494,469
Mass Flow (lb/hr)	2,589,000	2,372,000	2,191,000
Temperature (°F)	776	812	843
Moisture (% vol)	5.71	6.36	7.78
Moisture (% mass)	3.58	4.00	4.92
Oxygen (% vol)	14.94	14.85	14.64
Oxygen (% mass)	16.66	16.60	16.46
Molecular Weight	28.69	28.62	28.46
Water Injected (lb/hr)	29,770	26,320	19,980
Diameter (ft)	13.8	13.8	13.8
Velocity (ft/sec)	150.5	142.3	135.4

Note: Data from GE combustion turbine performance and emission guarantees.

Table A-7. Maximum Criteria Pollutant Emissions for Florida Power Corporation DeBary CT Project (Fuel Oil at 75% Load)

Pollutant	GE PG 7111EA No.2 Oil at 20°F	GE PG 7111EA No.2 Oil at 59°F	GE PG 7111EA No.2 Oil at 90°F
Particulate			
Basis	–	–	–
lb/hr	15.0	15.0	15.0
TPY	65.7	65.7	65.7
Sulfur Dioxide			
Basis	0.5% Sulfur	0.5% Sulfur	0.5% Sulfur
lb/hr	434.70	395.10	361.29
TPY	1,904.0	1,730.5	1,582.5
Nitrogen Oxides			
Basis (Thermal NO_x)	42 ppm[a]	42 ppm[a]	42 ppm[a]
lb/hr	141.0	128.2	116.8
TPY	617.5	561.6	511.8
ppm[b]	42.0	42.0	42.0
Carbon Monoxide			
Basis	25 ppm[c]	25 ppm[c]	25 ppm[c]
lb/hr	59.6	54.3	49.7
TPY	260.9	237.9	217.7
ppm	25.0	25.0	25.0
VOCs			
Basis	5.0 lb/hr	4.5 lb/hr	4.5 lb/hr
lb/hr	5.00	4.50	4.50
TPY	21.9	19.7	19.7
Lead			
Basis	EPA(1988)	EPA(1988)	EPA(1988)
lb/hr	7.18×10^{-3}	6.52×10^{-3}	5.96×10^{-3}
TPY	3.14×10^{-2}	2.86×10^{-2}	2.61×10^{-2}

[a] Corrected to 15% O_2 dry conditions.

[b] Does not include an allowance for fuel-bound nitrogen of 0.015 percent or greater.

[c] Corrected to dry conditions.

Table A-8. Maximum Other Regulated Pollutant Emissions for Florida Power Corporation DeBary CT Project (Fuel Oil at 75% Load)

Pollutant	GE PG 7111EA No.2 Oil at 20°F	GE PG 7111EA No.2 Oil at 59°F	GE PG 7111EA No.2 Oil at 90°F
Arsenic			
lb/hr	3.39×10^{-3}	3.08×10^{-3}	2.81×10^{-3}
TPY	1.48×10^{-2}	1.35×10^{-2}	1.23×10^{-2}
Beryllium			
lb/hr	2.02×10^{-3}	1.83×10^{-3}	1.68×10^{-3}
TPY	8.83×10^{-3}	8.03×10^{-3}	7.34×10^{-3}
Mercury			
lb/hr	2.42×10^{-3}	2.20×10^{-3}	2.01×10^{-3}
TPY	1.06×10^{-2}	9.63×10^{-3}	8.81×10^{-3}
Fluorine			
lb/hr	2.62×10^{-2}	2.38×10^{-2}	2.18×10^{-2}
TPY	1.15×10^{-1}	1.04×10^{-1}	9.54×10^{-2}
Sulfuric acid			
lb/hr	54.1	49.2	45.0
TPY	237.1	215.5	197.1

Sources: EPA, 1988; EPA, 1980.

Table A-9. Maximum Nonregulated Pollutant Emissions for Florida Power Corporation DeBary CT Project (Fuel Oil at 75% Load)

Pollutant	Gas Turbine No.2 Oil at 40°F	Gas Turbine No.2 Oil at 59°F	Gas Turbine No.2 Oil at 90°F
Manganese			
lb/hr	5.19×10^{-3}	4.72×10^{-3}	4.32×10^{-3}
TPY	2.27×10^{-2}	2.07×10^{-2}	1.89×10^{-2}
Nickel			
lb/hr	1.37×10^{-1}	1.25×10^{-1}	1.14×10^{-1}
TPY	6.00×10^{-1}	5.46×10^{-1}	4.99×10^{-1}
Cadmium			
lb/hr	8.47×10^{-3}	7.70×10^{-3}	7.04×10^{-3}
TPY	3.71×10^{-2}	3.37×10^{-2}	3.08×10^{-2}
Chromium			
lb/hr	3.83×10^{-2}	3.48×10^{-2}	3.18×10^{-2}
TPY	1.68×10^{-1}	1.52×10^{-1}	1.39×10^{-1}
Copper			
lb/hr	2.26×10^{-1}	2.05×10^{-1}	1.88×10^{-1}
TPY	9.89×10^{-1}	8.99×10^{-1}	8.22×10^{-1}
Vanadium			
lb/hr	5.62×10^{-2}	5.11×10^{-2}	4.67×10^{-2}
TPY	2.46×10^{-1}	2.24×10^{-1}	2.05×10^{-1}
Selenium			
lb/hr	1.89×10^{-2}	1.72×10^{-2}	1.57×10^{-2}
TPY	8.29×10^{-2}	7.54×10^{-2}	6.89×10^{-2}
Polycyclic Organic Matter			
lb/hr	2.25×10^{-4}	2.04×10^{-4}	1.87×10^{-4}
TPY	9.85×10^{-4}	8.95×10^{-4}	8.19×10^{-4}
Formaldehyde			
lb/hr	3.27×10^{-1}	2.97×10^{-1}	2.71×10^{-1}
TPY	1.43	1.30	1.19

Source: EPA, 1988.

Table A-15. Maximum Emissions for Additional Nonregulated Pollutants for Florida Power Corporation DeBary CT Project (Fuel Oil at 50% Load)

Pollutant	Gas Turbine No.2 Oil at 40°F	Gas Turbine No.2 Oil at 59°F	Gas Turbine No.2 Oil at 90°F
Antimony			
lb/hr	1.30×10^{-2}	1.19×10^{-2}	1.10×10^{-2}
TPY	5.68×10^{-2}	5.19×10^{-2}	4.80×10^{-2}
Barium			
lb/hr	1.16×10^{-2}	1.06×10^{-2}	9.79×10^{-3}
TPY	5.07×10^{-2}	4.64×10^{-2}	4.29×10^{-2}
Colbalt			
lb/hr	5.38×10^{-3}	4.92×10^{-3}	4.55×10^{-3}
TPY	2.35×10^{-2}	2.15×10^{-2}	1.99×10^{-2}
Zinc			
lb/hr	4.05×10^{-1}	3.71×10^{-1}	3.43×10^{-1}
TPY	1.78	1.62	1.50
Chlorine[a]			
lb/hr	1.60×10^{-2}	1.46×10^{-2}	1.35×10^{-2}
TPY	7.00×10^{-2}	6.41×10^{-2}	5.92×10^{-2}

[a] Assumes 0.5 ppm in fuel oil.

Source: EPA, 1979.

Table A-10. Maximum Emissions for Additional Nonregulated Pollutants for Florida Power Corporation DeBary CT Project (Fuel Oil at 75% Load)

Pollutant	Gas Turbine No.2 Oil at 40°F	Gas Turbine No.2 Oil at 59°F	Gas Turbine No.2 Oil at 90°F
Antimony			
lb/hr	$1.76\text{x}10^{-2}$	$1.60\text{x}10^{-2}$	$1.46\text{x}10^{-2}$
TPY	$7.72\text{x}10^{-2}$	$7.01\text{x}10^{-2}$	$6.41\text{x}10^{-2}$
Barium			
lb/hr	$1.57\text{x}10^{-2}$	$1.43\text{x}10^{-2}$	$1.31\text{x}10^{-2}$
TPY	$6.89\text{x}10^{-2}$	$6.27\text{x}10^{-2}$	$5.73\text{x}10^{-2}$
Colbalt			
lb/hr	$7.31\text{x}10^{-3}$	$6.64\text{x}10^{-3}$	$6.07\text{x}10^{-3}$
TPY	$3.20\text{x}10^{-2}$	$2.91\text{x}10^{-2}$	$2.66\text{x}10^{-2}$
Zinc			
lb/hr	$5.51\text{x}10^{-1}$	$5.01\text{x}10^{-1}$	$4.58\text{x}10^{-1}$
TPY	2.41	2.19	2.01
Chlorine[a]			
lb/hr	$2.17\text{x}10^{-2}$	$1.98\text{x}10^{-2}$	$1.81\text{x}10^{-2}$
TPY	$9.52\text{x}10^{-2}$	$8.65\text{x}10^{-2}$	$7.91\text{x}10^{-2}$

[a] Assumes 0.5 ppm in fuel oil.

Source: EPA, 1979.

Table A-14. Maximum Nonregulated Pollutant Emissions for Florida Power Corporation DeBary CT Project (Fuel Oil at 50% Load)

Pollutant	Gas Turbine No.2 Oil at 40°F	Gas Turbine No.2 Oil at 59°F	Gas Turbine No.2 Oil at 90°F
Manganese			
lb/hr	$3.82x10^{-3}$	$3.50x10^{-3}$	$3.23x10^{-3}$
TPY	$1.67x10^{-2}$	$1.53x10^{-2}$	$1.42x10^{-2}$
Nickel			
lb/hr	$1.01x10^{-1}$	$9.23x10^{-2}$	$8.53x10^{-2}$
TPY	$4.42x10^{-1}$	$4.04x10^{-1}$	$3.74x10^{-1}$
Cadmium			
lb/hr	$6.23x10^{-3}$	$5.70x10^{-3}$	$5.27x10^{-3}$
TPY	$2.73x10^{-2}$	$2.50x10^{-2}$	$2.31x10^{-2}$
Chromium			
lb/hr	$2.82x10^{-2}$	$2.58x10^{-2}$	$2.38x10^{-2}$
TPY	$1.23x10^{-1}$	$1.13x10^{-1}$	$1.04x10^{-1}$
Copper			
lb/hr	$1.66x10^{-1}$	$1.52x10^{-1}$	$1.40x10^{-1}$
TPY	$7.27x10^{-1}$	$6.66x10^{-1}$	$6.15x10^{-1}$
Vanadium			
lb/hr	$4.14x10^{-2}$	$3.78x10^{-2}$	$3.50x10^{-2}$
TPY	$1.81x10^{-1}$	$1.66x10^{-1}$	$1.53x10^{-1}$
Selenium			
lb/hr	$1.39x10^{-2}$	$1.27x10^{-2}$	$1.18x10^{-2}$
TPY	$6.10x10^{-2}$	$5.58x10^{-2}$	$5.16x10^{-2}$
Polycyclic Organic Matter			
lb/hr	$1.65x10^{-4}$	$1.51x10^{-4}$	$1.40x10^{-4}$
TPY	$7.25x10^{-4}$	$6.63x10^{-4}$	$6.13x10^{-4}$
Formaldehyde			
lb/hr	$2.40x10^{-1}$	$2.20x10^{-1}$	$2.03x10^{-1}$
TPY	1.05	$9.63x10^{-1}$	$8.90x10^{-1}$

Source: EPA, 1988.

Table A-11. Design Information and Stack Parameters for Florida Power Corporation DeBary CT Project (CT Performance Data For Fuel Oil at 50% Load)

Data	GE PG 7111EA No.2 Oil at 20°F	GE PG 7111EA No.2 Oil at 59°F	GE PG 7111EA No.2 Oil at 90°F
General			
Power (kW)	48,380.0	42,670.0	37,810.0
Heat Rate (Btu/kWh)	12,260.0	12,720.0	13,270.0
Heat Input (10^6 Btu/hr)	593.1	542.8	501.7
Fuel Oil (lb/hr)	31,975.1	29,259.4	27,047.9
Fuel			
Heat Content--Oil(LHV)	18,550.0	18,550.0	18,550.0
Percent Sulfur	0.5	0.5	0.5
CT Exhaust			
Volume Flow (acfm)	1,060,216	1,031,868	1,012,939
Volume Flow (scfm)	463,789	448,417	438,028
Mass Flow (lb/hr)	2,076,000	2,003,000	1,945,000
Temperature (°F)	747	755	761
Moisture (% vol)	4.87	5.34	6.67
Moisture (% mass)	3.05	3.35	4.21
Oxygen (% vol)	15.55	15.69	15.63
Oxygen (% mass)	17.31	17.50	17.54
Molecular Weight	28.75	28.69	28.52
Water Injected (lb/hr)	17,280	14,940	10,910
Diameter (ft)	14.5	14.5	14.5
Velocity (ft/sec)	107.3	104.4	102.5

Note: Data from GE combustion turbine performance and emission guarantees.

Table A-12. Maximum Criteria Pollutant Emissions for Florida Power Corporation DeBary CT Project (Fuel Oil at 50% Load)

Pollutant	GE PG 7111EA No.2 Oil at 20°F	GE PG 7111EA No.2 Oil at 59°F	GE PG 7111EA No.2 Oil at 90°F
Particulate			
Basis	—	—	—
lb/hr	15.0	15.0	15.0
TPY	65.7	65.7	65.7
Sulfur Dioxide			
Basis	0.5% Sulfur	0.5% Sulfur	0.5% Sulfur
lb/hr	319.75	292.59	270.48
TPY	1,400.5	1,281.6	1,184.7
Nitrogen Oxides			
Basis (Thermal NO_x)	42 ppm[a]	42 ppm[a]	42 ppm[a]
lb/hr	102.4	93.6	86.5
TPY	448.4	410.0	378.9
ppm[b]	42.0	42.0	42.0
Carbon Monoxide			
Basis	36 ppm[c]	40 ppm[c]	28 ppm[c]
lb/hr	69.2	74.0	49.9
TPY	303.3	324.2	218.6
ppm	36.0	40.0	28.0
VOCs			
Basis	6.5 lb/hr	5.5 lb/hr	5.0 lb/hr
lb/hr	6.50	5.50	5.00
TPY	28.5	24.1	21.9
Lead			
Basis	EPA(1988)	EPA(1988)	EPA(1988)
lb/hr	$5.28\text{x}10^{-3}$	$4.83\text{x}10^{-3}$	$4.47\text{x}10^{-3}$
TPY	$2.31\text{x}10^{-2}$	$2.12\text{x}10^{-2}$	$1.96\text{x}10^{-2}$

[a] Corrected to 15% O_2 dry conditions.

[b] Does not include an allowance for fuel-bound nitrogen of 0.015 percent or greater.

[c] Corrected to dry conditions.

Table A-13. Maximum Other Regulated Pollutant Emissions for Florida Power Corporation DeBary CT Project (Fuel Oil at 50% Load)

Pollutant	GE PG 7111EA No.2 Oil at 20°F	GE PG 7111EA No.2 Oil at 59°F	GE PG 7111EA No.2 Oil at 90°F
Arsenic			
lb/hr	2.49×10^{-3}	2.28×10^{-3}	2.11×10^{-3}
TPY	1.09×10^{-2}	9.98×10^{-3}	9.23×10^{-3}
Beryllium			
lb/hr	1.48×10^{-3}	1.36×10^{-3}	1.25×10^{-3}
TPY	6.49×10^{-3}	5.94×10^{-3}	5.49×10^{-3}
Mercury			
lb/hr	1.78×10^{-3}	1.63×10^{-3}	1.51×10^{-3}
TPY	7.79×10^{-3}	7.13×10^{-3}	6.59×10^{-3}
Fluorine			
lb/hr	1.93×10^{-2}	1.76×10^{-2}	1.63×10^{-2}
TPY	8.44×10^{-2}	7.73×10^{-2}	7.14×10^{-2}
Sulfuric acid			
lb/hr	39.8	36.4	33.7
TPY	174.4	159.6	147.5

Sources: EPA, 1988; EPA, 1980.

Table A-16. Design Information and Stack Parameters for Florida Power Corporation DeBary CT Project (CT Performance Data For Fuel Oil at 25% Load)

Data	GE PG 7111EA No.2 Oil at 20°F	GE PG 7111EA No.2 Oil at 59°F	GE PG 7111EA No.2 Oil at 90°F
<u>General</u>			
Power (kW)	24,150.0	21,330.0	18,880.0
Heat Rate (Btu/kWh)	16,550.0	17,590.0	18,800.0
Heat Input (10^6 Btu/hr)	399.7	375.2	354.9
Fuel Oil (lb/hr)	21,546.2	20,226.1	19,134.4
<u>Fuel</u>			
Heat Content--Oil(LHV)	18,550.0	18,550.0	18,550.0
Percent Sulfur	0.5	0.5	0.5
<u>CT Exhaust</u>			
Volume Flow (acfm)	896,548	878,492	860,936
Volume Flow (scfm)	456,487	429,087	405,870
Mass Flow (lb/hr)	2,049,000	1,920,000	1,806,000
Temperature (°F)	577	621	660
Moisture (% vol)	3.12	3.90	5.57
Moisture (% mass)	1.95	2.44	3.51
Oxygen (% vol)	17.32	17.15	16.82
Oxygen (% mass)	19.22	19.10	18.83
Molecular Weight	28.83	28.74	28.58
Water Injected (lb/hr)	8,390	7,700	5,580
Diameter (ft)	14.5	14.5	14.5
Velocity (ft/sec)	90.7	88.9	87.1

Note: Data from GE combustion turbine performance and emission guarantees.

Table A-17. Maximum Criteria Pollutant Emissions for Florida Power Corporation DeBary CT Project (Fuel Oil at 75% Load)

Pollutant	GE PG 7111EA No.2 Oil at 20°F	GE PG 7111EA No.2 Oil at 59°F	GE PG 7111EA No.2 Oil at 90°F
Particulate			
Basis	–	–	–
lb/hr	15.0	15.0	15.0
TPY	65.7	65.7	65.7
Sulfur Dioxide			
Basis	0.5% Sulfur	0.5% Sulfur	0.5% Sulfur
lb/hr	215.46	202.26	191.34
TPY	943.7	885.9	838.1
Nitrogen Oxides			
Basis (Thermal NO_x)	42 ppm[a]	42 ppm[a]	42 ppm[a]
lb/hr	68.2	64.1	60.4
TPY	298.8	280.9	264.4
ppm[b]	42.0	42.0	42.0
Carbon Monoxide			
Basis	60 ppm[c]	60 ppm[c]	48 ppm[c]
lb/hr	115.7	107.9	80.2
TPY	506.6	472.4	351.3
ppm	60.0	60.0	48.0
VOCs			
Basis	7.0 lb/hr	6.0 lb/hr	6.0 lb/hr
lb/hr	7.00	6.00	6.00
TPY	30.7	26.3	26.3
Lead			
Basis	EPA(1988)	EPA(1988)	EPA(1988)
lb/hr	3.56×10^{-3}	3.34×10^{-3}	3.16×10^{-3}
TPY	1.56×10^{-2}	1.46×10^{-2}	1.38×10^{-2}

[a] Corrected to 15% O_2 dry conditions.

[b] Does not include an allowance for fuel-bound nitrogen of 0.015 percent or greater.

[c] Corrected to dry conditions.

Table A-18. Maximum Other Regulated Pollutant Emissions for Florida Power Corporation DeBary CT Project (Fuel Oil at Peak Load)

Pollutant	GE PG 7111EA No.2 Oil at 20°F	GE PG 7111EA No.2 Oil at 59°F	GE PG 7111EA No.2 Oil at 90°F
Arsenic			
lb/hr	1.68×10^{-3}	1.58×10^{-3}	1.49×10^{-3}
TPY	7.35×10^{-3}	6.90×10^{-3}	6.53×10^{-3}
Beryllium			
lb/hr	9.99×10^{-4}	9.38×10^{-4}	8.87×10^{-4}
TPY	4.38×10^{-3}	4.11×10^{-3}	3.89×10^{-3}
Mercury			
lb/hr	1.20×10^{-3}	1.13×10^{-3}	1.06×10^{-3}
TPY	5.25×10^{-3}	4.93×10^{-3}	4.66×10^{-3}
Fluoride			
lb/hr	1.30×10^{-2}	1.22×10^{-2}	1.15×10^{-2}
TPY	5.69×10^{-2}	5.34×10^{-2}	5.05×10^{-2}
Sulfuric acid			
lb/hr	26.8	25.2	23.8
TPY	117.5	110.3	104.4

Sources: EPA, 1988; EPA, 1980.

Table A-19. Maximum Nonregulated Pollutant Emissions for Florida Power Corporation DeBary CT Project (Fuel Oil at 50% Load)

Pollutant	Gas Turbine No.2 Oil at 40°F	Gas Turbine No.2 Oil at 59°F	Gas Turbine No.2 Oil at 90°F
Manganese			
lb/hr	$2.57\text{x}10^{-3}$	$2.42\text{x}10^{-3}$	$2.29\text{x}10^{-3}$
TPY	$1.13\text{x}10^{-2}$	$1.06\text{x}10^{-2}$	$1.00\text{x}10^{-2}$
Nickel			
lb/hr	$6.79\text{x}10^{-2}$	$6.38\text{x}10^{-2}$	$6.03\text{x}10^{-2}$
TPY	$2.98\text{x}10^{-1}$	$2.79\text{x}10^{-1}$	$2.64\text{x}10^{-1}$
Cadmium			
lb/hr	$4.20\text{x}10^{-3}$	$3.94\text{x}10^{-3}$	$3.73\text{x}10^{-3}$
TPY	$1.84\text{x}10^{-2}$	$1.73\text{x}10^{-2}$	$1.63\text{x}10^{-2}$
Chromium			
lb/hr	$1.90\text{x}10^{-2}$	$1.78\text{x}10^{-2}$	$1.69\text{x}10^{-2}$
TPY	$8.32\text{x}10^{-2}$	$7.81\text{x}10^{-2}$	$7.38\text{x}10^{-2}$
Copper			
lb/hr	$1.12\text{x}10^{-1}$	$1.05\text{x}10^{-1}$	$9.94\text{x}10^{-2}$
TPY	$4.90\text{x}10^{-1}$	$4.60\text{x}10^{-1}$	$4.35\text{x}10^{-1}$
Vanadium			
lb/hr	$2.79\text{x}10^{-2}$	$2.62\text{x}10^{-2}$	$2.47\text{x}10^{-2}$
TPY	$1.22\text{x}10^{-1}$	$1.15\text{x}10^{-1}$	$1.08\text{x}10^{-1}$
Selenium			
lb/hr	$9.38\text{x}10^{-3}$	$8.81\text{x}10^{-3}$	$8.33\text{x}10^{-3}$
TPY	$4.11\text{x}10^{-2}$	$3.86\text{x}10^{-2}$	$3.65\text{x}10^{-2}$
Polycyclic Organic Matter			
lb/hr	$1.11\text{x}10^{-4}$	$1.05\text{x}10^{-4}$	$9.90\text{x}10^{-5}$
TPY	$4.88\text{x}10^{-4}$	$4.58\text{x}10^{-4}$	$4.34\text{x}10^{-4}$
Formaldehyde			
lb/hr	$1.62\text{x}10^{-1}$	$1.52\text{x}10^{-1}$	$1.44\text{x}10^{-1}$
TPY	$7.09\text{x}10^{-1}$	$6.66\text{x}10^{-1}$	$6.30\text{x}10^{-1}$

Source: EPA, 1988.

Table A-20. Maximum Emissions for Additional Nonregulated Pollutants for Florida Power Corporation DeBary CT Project (Fuel Oil at 25% Load)

Pollutant	Gas Turbine No.2 Oil at 40°F	Gas Turbine No.2 Oil at 59°F	Gas Turbine No.2 Oil at 90°F
Antimony			
lb/hr	$8.73\text{x}10^{-3}$	$8.20\text{x}10^{-3}$	$7.75\text{x}10^{-3}$
TPY	$3.82\text{x}10^{-2}$	$3.59\text{x}10^{-2}$	$3.40\text{x}10^{-2}$
Barium			
lb/hr	$7.80\text{x}10^{-3}$	$7.32\text{x}10^{-3}$	$6.93\text{x}10^{-3}$
TPY	$3.42\text{x}10^{-2}$	$3.21\text{x}10^{-2}$	$3.03\text{x}10^{-2}$
Colbalt			
lb/hr	$3.62\text{x}10^{-3}$	$3.40\text{x}10^{-3}$	$3.22\text{x}10^{-3}$
TPY	$1.59\text{x}10^{-2}$	$1.49\text{x}10^{-2}$	$1.41\text{x}10^{-2}$
Zinc			
lb/hr	$2.73\text{x}10^{-1}$	$2.56\text{x}10^{-1}$	$2.43\text{x}10^{-1}$
TPY	1.20	1.12	1.06
Chlorine[a]			
lb/hr	$1.08\text{x}10^{-2}$	$1.01\text{x}10^{-2}$	$9.57\text{x}10^{-3}$
TPY	$4.72\text{x}10^{-2}$	$4.43\text{x}10^{-2}$	$4.19\text{x}10^{-2}$

[a] Assumes 0.5 ppm in fuel oil.

Source: EPA, 1979.

APPENDIX B

REVIEW OF PSD PRECONSTRUCTION MONITORING REQUIREMENT BY THE FLORIDA DEPARTMENT OF ENVIRONMENTAL REGULATION

Florida Department of Environmental Regulation

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

Bob Martinez, Governor Dale Twachtmann, Secretary John Shearer, Assistant Secretary

July 27, 1990

Ms. Judy Corces
Florida Power Corporation
3201 34th Street
St. Petersburg, Florida 33711

Dear Ms. Corces:

Re: PSD Preconstruction Monitoring Requirement for Debary Site

We have reviewed your proposal to use Site No. 0930-001-F02 at Debary to satisfy the PSD preconstruction monitoring requirements for SO_2 for your project to add 450 MW of turbines at your Debary facility. We have determined that data collected at this site is acceptable for satisfying these requirements.

If you have any questions, please call Cleve Holladay at (904)488-1344.

Sincerely,

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

CHF/plm

c: Robert C. McCann, KBN

Florida Power
CORPORATION

May 10, 1990

Mr. Clair H. Fancy, Chief
Bureau of Air Regulation
Division of Air Resources Management
Department of Environmental Regulation
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32301

Dear Mr. Fancy,

As discussed at the March 27th meeting between Florida Department of Environmental Regulation (FDER) and Florida Power Corporation (FPC), FPC is planning the addition of 450 megawatts (MW) of simple cycle combustion turbines at the DeBary site. Enclosed is the "Preliminary Air Quality Impact Assessment for Evaluating the Site Location of 450 MW of Simple Cycle Combustion Turbines at the FPC DeBary Facility" report, prepared by KBN Engineering and Applied Sciences, Inc. (KBN) for FPC.

Section 4.0 of the enclosed report, Existing Monitoring Data, shows that existing air quality monitoring data should be appropriate to satisfy the PSD preconstruction monitoring requirements for this project. Therefore, FPC requests that FDER review the enclosed report and determine if the existing monitoring data will be acceptable to the FDER as preconstruction monitoring for the air construction permit.

Thank you for your consideration of this matter.

Sincerely,

Judy N. Corces

Judy N. Corces

PYB/sss
PYB:#1:Fancy.ltr

Encl.

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