



May 3, 1991

RECEIVED

MAY 3 1991

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

Bureau of  
Air Regulation

Subject: Air Construction and Prevention of Significant Deterioration (PSD)  
Permit Applications--Lake and Pasco Counties Cogeneration Facilities

Dear Clair:

Please find enclosed two applications to construct air pollution sources and accompanying PSD permit applications for cogeneration facilities located in Lake and Pasco Counties. The applicants for these projects are Lake Cogen Limited and Pasco Cogen Limited, which are the entities that will own and control each facility. These entities have been formed by Peoples Cogeneration Company, a subsidiary of Peoples Gas Company. The electrical power that will be generated by these facilities will be purchased by Florida Power Corporation. The inherent efficiency of these new units will make them among the most efficient in the state.

The Lake County facility will be located on property leased from Golden Gem Growers; the Pasco County facility will be located on property leased from the Lykes-Pasco citrus processing plant. The cogeneration facilities will supply process steam, which is currently generated by existing boilers, for each citrus plant. While this will obviate the need to use the existing boilers when the cogeneration plant is operating, it is desired that the citrus and cogeneration plants be independent. Thus, while there will be an actual reduction in air pollutants generated at the citrus plants, this permit request does not take into account any emissions reductions, and the existing permitted emissions from these facilities would not be affected.

The technical information submitted on each facility is identical. Only the meteorological data used in the modeling analyses changed. Therefore, it may be appropriate to have the permit applications reviewed by one engineer.

I am submitting five copies of each application. As required, I have enclosed a \$5,000 check made out to the Florida Department of Environmental Regulation for each application. Although there will be two sources at each cogeneration facility, each source is identical and thus the Similar Source Fee is applicable.

90115A1/11

**KBN ENGINEERING AND APPLIED SCIENCES, INC.**

1034 Northwest 57th Street Gainesville, Florida 32605 904/331-9000 FAX: 904/332-4189

EQUAL EMPLOYMENT OPPORTUNITY / AN AFFIRMATIVE ACTION EMPLOYER

May 2, 1991  
Page 2



I would like to establish a meeting in the near future to review with your staff any initial comments they may have. I'll call Barry Andrews of your staff in about a week to set up a convenient time for a meeting.

Sincerely,

A handwritten signature in cursive script that reads "Kennard F. Kosky".

Kennard F. Kosky, P.E.  
President and Principal Engineer

KFK/tyf

cc: E.L. Mize

*P. Lewis*

*C. Paladano*

*B. Thomas*

*C. Collins*

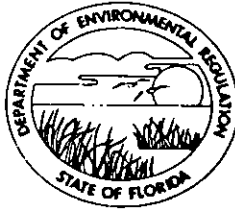
*G. Harper, EPA*

*C. Shaw, DPE*

## DEPARTMENT OF ENVIRONMENTAL REGULATION

RECEIVED

MAY 3 1991

Bureau of  
Air Regulation

AC 35-196459

PSD-FL-176

\$5,000pd.  
5-3-91  
Receipt # 151268

## APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: Cogeneration Facility ☒ New<sup>1</sup> ☐ Existing<sup>1</sup>APPLICATION TYPE: ☒ Construction ☐ Operation ☐ ModificationCOMPANY NAME: Lake Cogen Limited COUNTY: LakeIdentify 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) Cogen Units 1 and 2SOURCE LOCATION: Street State Road 19 City UmatillaUTM: East 434.0 km North 3,198.8 kmLatitude 28° 55' 02" N Longitude 81° 40' 37" WAPPLICANT NAME AND TITLE: Ernest L. Mize, Vice PresidentAPPLICANT ADDRESS: 535 North Ferncreek Avenue, Orlando, FL 32803

## SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

## A. APPLICANT

I am the undersigned owner or authorized representative\* of Lake Cogen Limited

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

\*Attach letter of authorization

Signed: Ernest L. MizeErnest L. Mize, Vice President

Name and Title (Please Type)

Date: 5/1/91 Telephone No. (407) 843-2139

- 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

<sup>1</sup>See Florida Administration Code Rule 17-2.100(57) and (104)

**PREVENTION OF SIGNIFICANT  
DETERIORATION  
PERMIT APPLICATION FOR  
THE PROPOSED  
LAKE COUNTY COGENERATION  
FACILITY**

**Prepared For:**

**Lake Cogen Limited  
535 North Ferncreek Avenue  
Orlando, FL 32803**

**Prepared By:**

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

**May 1991  
90116C1**

2. Instrumentation, Field and Laboratory

- a. Was instrumentation EPA referenced or its equivalent? ☐ Yes ☐ No
- b. Was instrumentation calibrated in accordance with Department procedures?  
☐ Yes ☐ No ☐ Unknown

B. Meteorological Data Used for Air Quality Modeling See Section 6.0 in PSD Application

1. \_\_\_\_\_ Year(s) of data from \_\_\_\_\_ / \_\_\_\_\_ / \_\_\_\_\_ to \_\_\_\_\_ / \_\_\_\_\_ / \_\_\_\_\_  
month day year month day year
2. Surface data obtained from (location) \_\_\_\_\_
3. Upper air (mixing height) data obtained from (location) \_\_\_\_\_
4. Stability wind rose (STAR) data obtained from (location) \_\_\_\_\_

C. Computer Models Used See Section 6.0 in PSD Application

1. \_\_\_\_\_ Modified? If yes, attach description.
2. \_\_\_\_\_ Modified? If yes, attach description.
3. \_\_\_\_\_ Modified? If yes, attach description.
4. \_\_\_\_\_ Modified? If yes, attach description.

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

D. Applicants Maximum Allowable Emission Data See Section 6.0 in PSD Application

Pollutant	Emission Rate
TSP	_____ grams/sec
SO <sup>2</sup>	_____ grams/sec

E. Emission Data Used in Modeling See Section 6.0 in PSD Application

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

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

G. Discuss the social and economic impact of the selected technology versus other applicable technologies (i.e, jobs, payroll, production, taxes, energy, etc.). Include assessment of the environmental impact of the sources. See Section 4.0 in PSD Application

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

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

Name (Please Type)

KBN Engineering and Applied Sciences, Inc.

Company Name (Please Type)

1034 NW 57th Street, Gainesville, FL 32605

Mailing Address (Please Type)

Florida Registration No. 14996 Date: 5/1/91 Telephone No. (904) 331-9000

SECTION II: GENERAL PROJECT INFORMATION

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

Construction of two combustion turbines and heat recovery steam generators;

Section 2.0 in PSD Application

- B. Schedule of project covered in this application (Construction Permit Application Only)  
Start of Construction October 1, 1991 Completion of Construction January 1, 1993
- C. Costs of pollution control system(s): (Note: Show breakdown of estimated costs only for individual components/units of the project serving pollution control purposes. Information on actual costs shall be furnished with the application for operation permit.)

The cost of control is integral to the design of the project; low NO<sub>x</sub> combustors and natural gas.

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

None

E. Requested permitted equipment operating time: hrs/day 24; days/wk 7; wks/yr 52;  
If power plant, hrs/yr 8,760; if seasonal, describe: \_\_\_\_\_  
See Section 2.0

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

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

a. If yes, has "offset" been applied? \_\_\_\_\_

b. If yes, has "Lowest Achievable Emission Rate" been applied? \_\_\_\_\_

c. If yes, list non-attainment pollutants. \_\_\_\_\_

2. Does best available control technology (BACT) apply to this source?

If yes, see Section VI. \_\_\_\_\_

YES

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

YES

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

YES

5. Do "National Emission Standards for Hazardous Air Pollutants"  
(NESHAP) apply to this source? \_\_\_\_\_

NO

H. Do "Reasonably Available Control Technology" (RACT) requirements apply  
to this source? \_\_\_\_\_

NO

a. If yes, for what pollutants? \_\_\_\_\_

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

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

PSD Permit Application is attached.

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

A. Raw Materials and Chemicals Used in your Process, if applicable: NOT APPLICABLE

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

B. Process Rate, if applicable: (See Section V, Item 1) NOT APPLICABLE

1. Total Process Input Rate (lbs/hr): \_\_\_\_\_

2. Product Weight (lbs/hr): \_\_\_\_\_

C. Airborne Contaminants Emitted: (Information in this table must be submitted for each emission point, use additional sheets as necessary)

SEE TABLE 2-1 IN PSD PERMIT APPLICATION

Name of Contaminant	Emission <sup>1</sup>		Allowed <sup>2</sup> Emission Rate per Rule 17-2	Allowable <sup>3</sup> Emission lbs/hr	Potential <sup>4</sup> Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
SO <sub>2</sub>	40	21.0	0.8% Sulfur	320	40	21.0	See
PM	10	27.0	NA	NA	10	27.0	Figure 2-1
NO <sub>x</sub>	68.5	404.7	113 ppmvd	184.3	68.5	404.7	in PSD
CO	75.5	466.5	NA	NA	75.5	466.5	Application
VOC	4.15	30.9	NA	NA	4.15	30.9	

<sup>1</sup>See Section V, Item 2. Per unit; oil firing

<sup>2</sup>Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input); NSPS - 0.8% sulfur oil and 75 ppmvd NO<sub>x</sub> corrected for heat rate; i.e., 113 ppmvd; FDER Rule 17-2.660.

<sup>3</sup>Calculated from operating rate and applicable standard.

<sup>4</sup>Emission, if source operated without control (See Section V, Item 3).



D. Control Devices: (See Section V, Item 4)  
See Section 4.0 in PSD Application

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

E. Fuels  
See Table A-1 in PSD Permit Application

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr/yr	max./hr	
Natural Gas-CT	<403,268.3 CF <sup>a</sup>	403,268.3 CF	383.1 @ ISO Conditions ✓
Natural Gas-DB	63,085.8 CF <sup>b</sup>	157,894.7 CF	150 ✓
Fuel Oil-CT	576 lb <sup>c</sup>	21,031.4 lb	387.0 @ ISO Conditions ✓

CT = Combustion Turbine; DB = Duct Burner

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

<sup>a</sup>8,760 hr/yr; <sup>b</sup>3,500 hr/yr; <sup>c</sup>240 hr/yr

Fuel Analysis:

Percent Sulfur: NG = 1 grain/100 CF; oil = 0.1% sulfur Percent Ash: <0.1

Density: ~7.2 for oil lbs/gal Typical Percent Nitrogen: <0.015

Heat Capacity: NG = 950 Btu/CF; Oil = 18,400 BTU/lb 132,480 (Oil) BTU/gal  
(LHV)

Other Fuel Contaminants (which may cause air pollution): See Appendix A in PSD Permit

Application

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

Annual Average \_\_\_\_\_ Maximum \_\_\_\_\_

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

Separate construction permits to be applied for wastewater.

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

Stack Height: 100 ft. Stack Diameter: 11 ft.  
 Gas Flow Rate: 324,249 ACFM 220,190 ✓ DSCFM Gas Exit Temperature: 232 °F.  
 Water Vapor Content: 11 % Velocity: 56.9 ✓ FPS

SECTION IV: INCINERATOR INFORMATION

NOT APPLICABLE

Type of Waste	Type 0 (Plastics)	Type II (Rubbish)	Type III (Refuse)	Type IV (Garbage)	Type IV (Pathological)	Type V (Liq. & Gas By-prod.)	Type VI (Solid By-prod.)
Actual lb/hr Incinerated							
Uncontrolled (lbs/hr)							

Description of Waste \_\_\_\_\_

Total Weight Incinerated (lbs/hr) \_\_\_\_\_ Design Capacity (lbs/hr) \_\_\_\_\_

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

Manufacturer \_\_\_\_\_

Date Constructed \_\_\_\_\_ Model No. \_\_\_\_\_

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

Stack Height: \_\_\_\_\_ ft. Stack Diameter: \_\_\_\_\_ Stack Temp. \_\_\_\_\_

Gas Flow Rate: \_\_\_\_\_ ACFM \_\_\_\_\_ DSCFM\* Velocity: \_\_\_\_\_ FPS

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

Type of pollution control devices: ☐ Cyclone ☐ Wet Scrubber ☐ Afterburner  
☐ Other (specify) \_\_\_\_\_

Brief description of operating characteristics of control devices: \_\_\_\_\_

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

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

#### SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]  
See Table A-1 in the PSD Application
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods, 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made. See Appendix A in PSD Application
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).  
See Appendix A in the PSD Application
4. With construction permit application, include design details for all air pollution control systems (e.g., for baghouse include cloth to air ratio; for scrubber include cross-section sketch, design pressure drop, etc.)  
See Table A-1 in the PSD Application
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency).  
See Appendix A in the PSD Application
6. An 8 1/2" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained.  
See Figure 2-1 in the PSD Application
7. An 8 1/2" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Examples: Copy of relevant portion of USGS topographic map).  
See Figure 1-1 in the PSD Application
8. An 8 1/2" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.  
See Figure 1-2 in the PSD Application

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation. Application fee attached
10. With an application for operation permit, attach a Certificate of Completion of Construction indicating that the source was constructed as shown in the construction permit.

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

- A. Are standards of performance for new stationary sources pursuant to 40 C.F.R. Part 60 applicable to the source? See Section 4.2 in PSD Application

☒ Yes ☐ No 40 CFR Part 60 Subpart GG; Subpart Db.

Contaminant	Rate or Concentration
NO <sub>x</sub> - CT	75 ppmvd corrected to 15% O <sub>2</sub> and heat rate
SO <sub>2</sub> - CT	0.8% sulfur
NO <sub>x</sub> - DB	0.2 lb/10 <sup>6</sup> Btu heat input

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

☒ Yes ☐ No See Section 4.0 in PSD Application

Contaminant	Rate or Concentration

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

Contaminant	Rate or Concentration
See Section 4.0 in PSD Application	

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

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

\*Explain method of determining

See Section 4.0 in PSD Application

5. Useful Life:

6. Operating Costs:

7. Energy:

8. Maintenance Cost:

9. Emissions:

Contaminant

Rate or Concentration


10. Stack Parameters

a. Height: ft.

b. Diameter ft.

c. Flow Rate: ACFM

d. Temperature: °F.

e. Velocity: FPS

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

1.

a. Control Devices:

b. Operating Principles:

c. Efficiency:<sup>1</sup>

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:<sup>2</sup>

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:<sup>1</sup>

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:<sup>2</sup>

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

<sup>1</sup>Explain method of determining efficiency.

<sup>2</sup>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:<sup>1</sup>
- d. Capital Cost:
- e. Useful Life:
- f. Operating Cost:
- g. Energy:<sup>2</sup>
- 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:<sup>1</sup>
- d. Capital Cost:
- e. Useful Life:
- f. Operating Cost:
- g. Energy:<sup>2</sup>
- h. Maintenance Cost:
- i. Availability of construction materials and process chemicals:
- j. Applicability to manufacturing processes:
- k. Ability to construct with control device, install in available space, and operate within proposed levels:

F. Describe the control technology selected:

- 1. Control Device:
- 2. Efficiency:<sup>1</sup>
- 3. Capital Cost:
- 4. Useful Life:
- 5. Operating Cost:
- 6. Energy:<sup>2</sup>
- 7. Maintenance Cost:
- 8. Manufacturer:
- 9. Other locations where employed on similar processes:
- a. (1) Company:
- (2) Mailing Address:
- (3) City:
- (4) State:

<sup>1</sup>Explain method of determining efficiency.

<sup>2</sup>Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:<sup>1</sup>

Contaminant

Rate or Concentration

(8) Process Rate:<sup>1</sup>

b. (1) Company:

(2) Mailing Address:

(3) City:

(4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:<sup>1</sup>

Contaminant

Rate or Concentration

(8) Process Rate:<sup>1</sup>

10. Reason for selection and description of systems:

<sup>1</sup>Applicant must provide this information when available. Should this information not be available, applicant must state the reason(s) why.

#### SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

A. Company Monitored Data Not Applicable; see Sections 3.4.2.2 and 5.2 in PSD Application

1. \_\_\_\_\_ no. sites \_\_\_\_\_ TSP \_\_\_\_\_ ( ) SO<sup>2</sup>\* \_\_\_\_\_ 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).

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## 1.0 INTRODUCTION

Lake Cogen Limited is proposing to locate a 108-megawatt (MW) cogeneration facility at the existing Golden Gem Citrus Processing Plant. The proposed site, which is located in Lake County (Figure 1-1), will be under the common control of Lake Cogen Limited. The proposed cogeneration facility will consist of two combustion turbines (CTs) with a generating capability of 42 MW (Table 1-1). A steam turbine using the steam generated by heat recovery steam generators (HRSGs) will have a generating capability of about 24 MW. The HRSG also will supply steam requirements for the citrus processing facility. A plot plan for the facility is presented in Figure 1-2.

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

The proposed project will be a major facility because emissions of at least one regulated pollutant exceeds 250 tons per year (TPY). PSD review is required for these emissions and for any pollutant for which the net increase in emissions exceeds the PSD significant emission rates. The potential emissions from the proposed project will exceed the PSD significant emission rates for nitrogen dioxide (NO<sub>2</sub>), carbon monoxide (CO), particulate matter (PM), particulate matter with an aerodynamic diameter of 10 micrometers (PM<sub>10</sub>), and arsenic (As). Therefore, the project is subject to PSD review for these pollutants.

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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 <sup>6</sup> 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 <sub>2</sub> SO <sub>4</sub>	sulfuric acid
Hg	mercury
HRSG	heat recovery steam generators
HSH	highest, second highest
ISC	Industrial Source Complex
ISCST	Industrial Source Complex Short-Term
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 <sub>3</sub>	ammonia
NO <sub>2</sub>	nitrogen dioxide
NO <sub>x</sub>	nitrogen oxides
NSCR	nonselective catalytic reduction
NSPS	New Source Performance Standards
NTL	No Threat Levels
NWS	National Weather Service

ACRONYMS AND ABBREVIATIONS

(Page 2 of 2)

PM(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
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective noncatalytic reduction
SO <sub>2</sub>	sulfuric dioxide
SO <sub>3</sub>	sulfuric trioxide
TPH	tons per hour
TPY	tons per year
UNAMAP	Users Network for Applied Modeling of Air Pollution
VOC	volatile organic compound

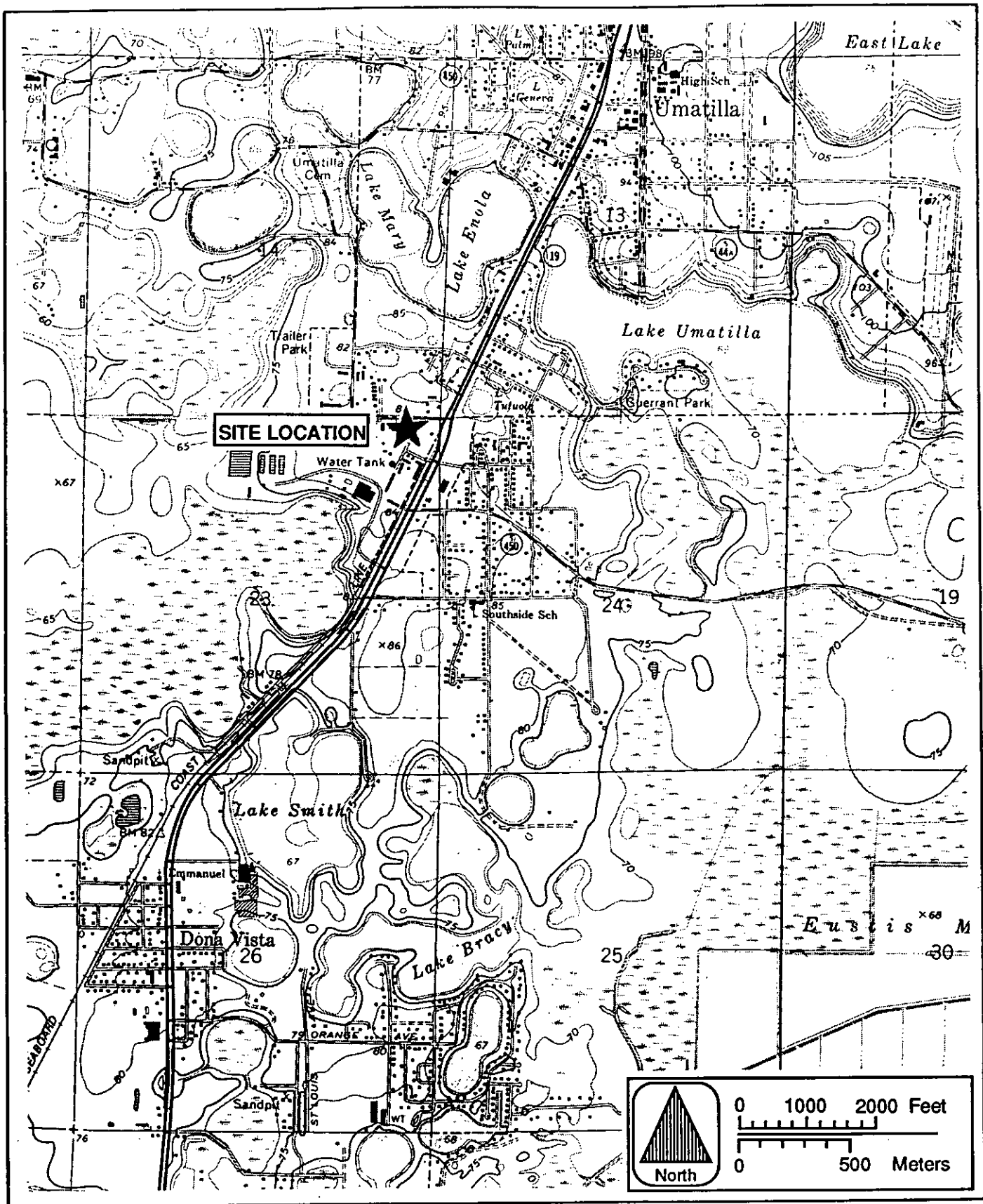


Table 1-1. Characteristics of the Lake County Cogeneration Facility

Characteristic	Data
<u>Capacity (kW)</u>	
Combustion Turbines (2)	84,088 <sup>a</sup>
Steam Cycle	23,611
Total	107,699
<u>Equipment Characteristics</u>	
Type of CT	GE LM 6000
Number of CTs	2
Number of HRSGs	2
Number of Steam Turbines	1
Process Steam (lb/hr)	20,000
<u>Fuels</u>	
Primary	Natural Gas
Emergency Backup (gas curtailment only)	Distillate Oil

Note: CT - Combustion turbine  
GE - General Electric  
HRSG - heat recovery steam generator

<sup>a</sup> Represents ISO conditions; actual performance expected to be 43,285 kW (gross) per machine at operating temperature of 51°F (see discussion in Section 2.2)



**Figure 1-1 LOCATION OF LAKE COUNTY  
COGENERATION FACILITY**

SOURCES: USGS, 1980; KBN, 1991.



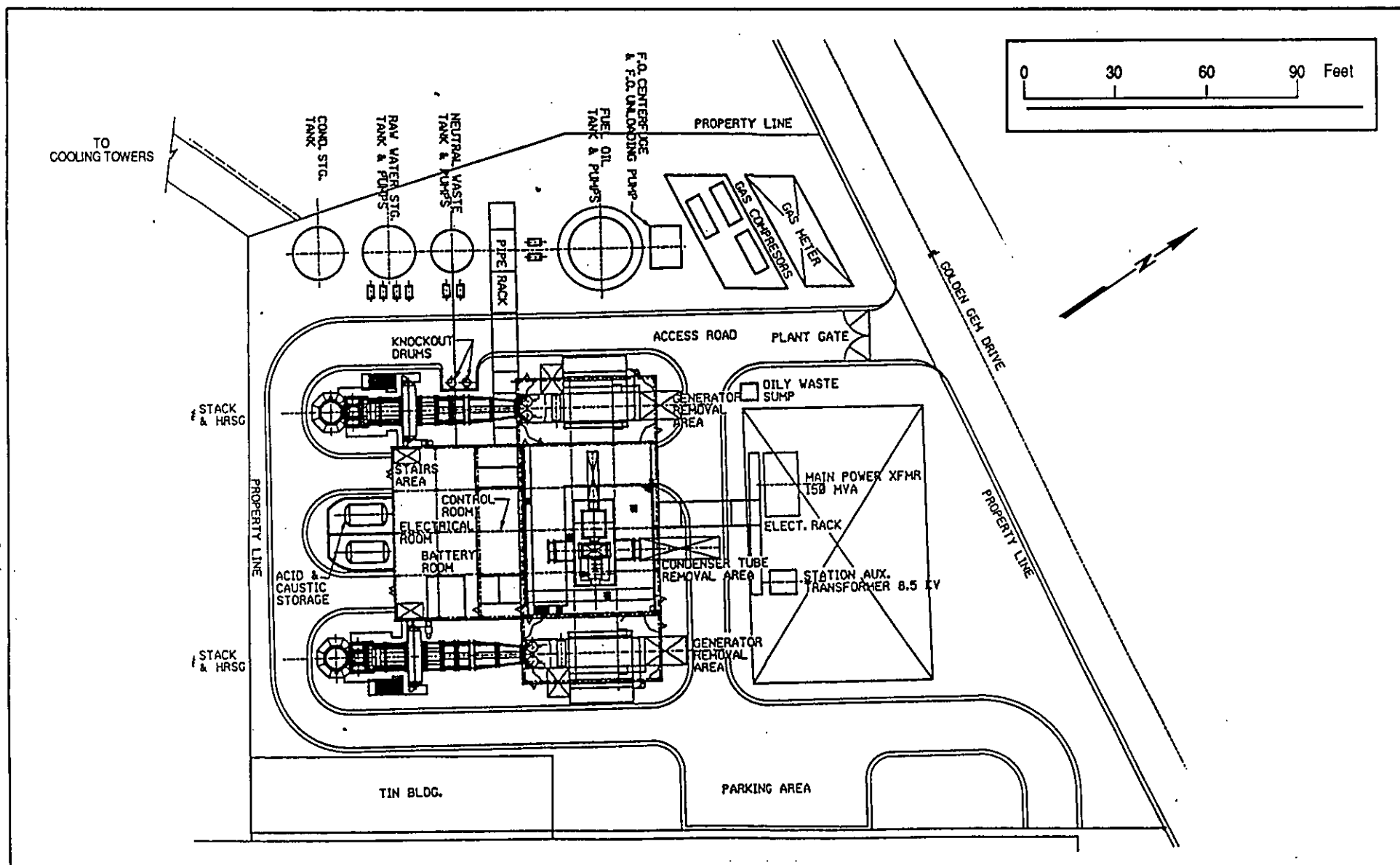


Figure 1-2 SITE PLAN OF PROPOSED FACILITY,  
LAKE COUNTY, FLORIDA

**KBN**

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

## 2.0 PROJECT DESCRIPTION

### 2.1 GENERAL DESCRIPTION

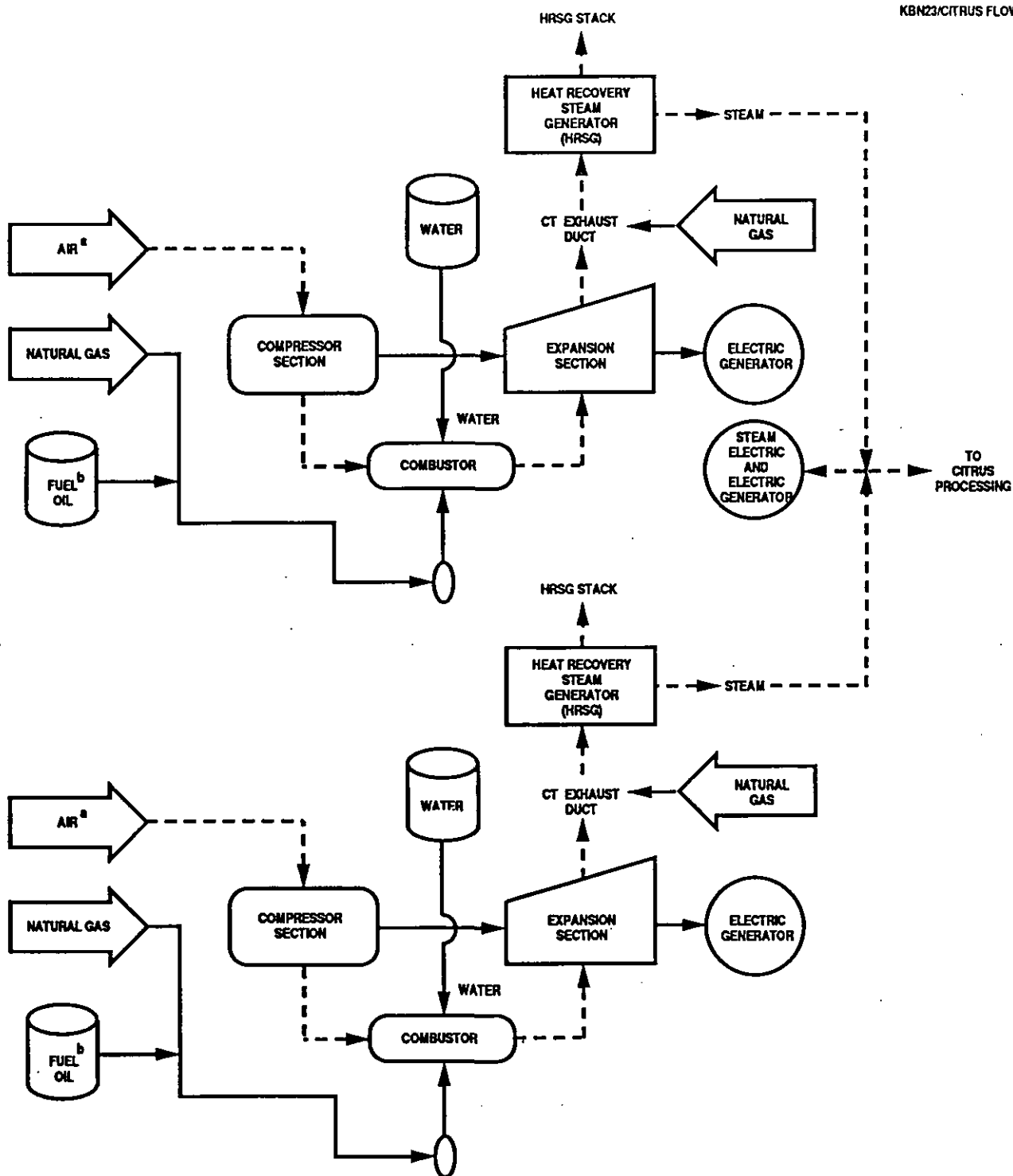
The proposed project will consist of two CTs and two HRSGs. The CTs will be the new General Electric (GE) LM 6000 machines. The LM 6000 is a newly developed aircraft derivative machine that has thermal efficiency of approximately 40 percent. This efficiency, developed from advanced aircraft compressor and turbine technology, makes the LM 6000 more efficient than the advanced heavy frame combustion turbine being offered by certain manufacturers (e.g., the GE Frame combustion turbine). A description of this machine is presented in Appendix A. Each CT will be served by a single HRSG, exhausting to an individual stack. There will be no bypass stacks on the CTs for simple cycle operation. A flow diagram of the project is presented in Figure 2-1.

The primary fuel for firing the CTs will be natural gas; distillate fuel oil will be used as emergency backup when natural gas is curtailed. Operation with distillate oil will not exceed 10 days per year. There will be supplementary firing of natural gas only in the HRSGs.

Air emission sources associated with the proposed project consist of the CTs and supplemental firing in the HRSGs. Wet injection will be used to control emissions of nitrogen oxides ( $\text{NO}_x$ ) from the CTs. The use of natural gas or low-sulfur (0.1-percent sulfur maximum) distillate fuel oil will minimize the emissions of sulfur dioxide ( $\text{SO}_2$ ) from the units.

### 2.2 FACILITY EMISSIONS AND STACK OPERATING PARAMETERS

The emissions and stack parameters for the CT are presented in Table 2-1. These data represent the maximum emissions since air inlet coolers will be installed on the CTs to maintain a compressor temperature of 51°F, which will increase generating capability and regulate temperature. Maximum potential annual emissions for the project are presented in Table 2-2. Performance information and maximum emission rates for regulated criteria



## NOTES:

- (a) COOLED FROM AMBIENT  
 (b) EMERGENCY BACKUP ONLY - 10 DAYS/YEAR

Figure 2-1 SIMPLIFIED FLOW DIAGRAM OF PROPOSED UNIT

**KBN**

Table 2-1. Stack, Operating, and Emission Data for the Proposed Cogeneration Facility (Maximum at ISO Conditions)

Parameter	Fuel Type		
	Fuel Oil <sup>a</sup> Gas Turbine	Natural Gas Gas Turbine <sup>b</sup>	Duct Burner <sup>c</sup>
<u>Stack Data (ft)</u>			
Height	100	100	d
Diameter	11	11	d
<u>Operating Data</u>			
Temperature (°F)	232	232	d
Velocity (ft/sec)	56.9	56.2	d
<u>Building Data (ft)</u>			
Height	51	51	d
Length	124	124	d
Width	80	80	d
<u>Maximum Hourly Emission Data (lb/hr) for Each Emission Unit/Fuel Type</u>			
SO <sub>2</sub>	40.0	1.15	0.45
PM	10.0	2.5	0.9
NO <sub>x</sub>	68.5	39.4	15.0
CO	75.5	40.3	30.0
VOC	4.15	1.65	4.5
Sulfuric acid mist	3.2	Neg	Neg
Pb	0.0034	-	-
<u>Annual Potential Emission Data (TPY) for Each Emission Unit/Fuel Type</u>			
SO <sub>2</sub>	4.8	5.05	0.79
PM	1.2	11.0	1.58
NO <sub>x</sub>	8.2	172.4	26.3
CO	9.1	176.6	52.5
VOC	0.5	7.2	7.9
Sulfuric Acid Mist	0.4	Neg	Neg
Pb	0.0004	Neg	Neg

<sup>a</sup> Performance based on NO<sub>x</sub> emissions of 42 ppmvd (corrected to 15 percent O<sub>2</sub>); SO<sub>2</sub> emissions based on an average sulfur content of 0.3 percent sulfur; annual emission data based on 240 hr/yr (10 days/year).

<sup>b</sup> Performance based on NO<sub>x</sub> emissions of 25 ppmvd (corrected to 15 percent O<sub>2</sub>); annual emissions data based on 8,760 hours/year (365 days/yr) operation.

<sup>c</sup> Performance based on 150 x 10<sup>6</sup> Btu/hour heat input per HRSG and 3,500 hours per year operation.

<sup>d</sup> Same as gas turbine natural gas; duct burners will not fire No. 2 oil.

Table 2-2. Maximum Annual Potential Emissions From Proposed Cogeneration Project

Pollutant	Distillate Oil <sup>a</sup>	Fuel (TPY)		Total (TPY)
		Natural Gas <sup>b</sup>		
		GT	DB	
SO <sub>2</sub>	9.6	9.8	1.6	21.0
PM <sup>c</sup>	2.4	21.4	3.2	27.0
NO <sub>x</sub>	16.4	335.4	52.6	404.7
CO	18.2	343.3	105.0	466.5
VOC	1.0	14.0	15.8	30.8
H <sub>2</sub> SO <sub>4</sub>	0.8	Neg	Neg	0.8
Pb	0.0008	Neg	Neg	0.0008

<sup>a</sup>240 hours/year (i.e., 10 days/year).

<sup>b</sup>8,520 hours/year operation.

<sup>c</sup>PM10.



pollutants, regulated noncriteria pollutants, and nonregulated pollutants from each CT are presented in Tables A-1 through A-5 of Appendix A.

Supplemental firing with natural gas will take place in the duct between each CT and its associated HRSG. The supplemental firing, at a maximum rate of 150 million British thermal units per hour ( $\times 10^6$  Btu/hr), will allow the HRSG to produce additional steam and therefore allow greater electrical power generation in the steam turbine/generator. The firing of natural gas will produce additional air emissions, as shown in Tables 2-1 and 2-2, for the maximum firing rate. These emissions will combine with the CT exhaust gases only during natural gas firing and exhaust through the HRSG stack. Supplemental firing will be limited to an equivalent of 3,500 hours per year at maximum capacity (i.e.,  $525,000 \times 10^6$  Btu).

### 3.0 AIR QUALITY REVIEW REQUIREMENTS AND APPLICABILITY

The following discussion pertains to the federal and state air regulatory requirements and their applicability to the proposed project. These regulations must be satisfied before the proposed 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 that has the potential to emit 100 TPY or more, or any other stationary facility that has the potential to emit 250 TPY or more of any pollutant regulated under CAA. "Potential to emit" means the capability, at maximum design capacity, to emit a pollutant after the application of control equipment.

Table 3-1. National and State AAQS, Allowable PSD Increments, and Significant Impact Levels ( $\mu\text{g}/\text{m}^3$ )

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

<sup>a</sup>Short-term maximum concentrations are not to be exceeded more than once per year.

<sup>b</sup>Maximum concentrations are not to be exceeded.

<sup>c</sup>Proposed October 5, 1989.

<sup>d</sup>Achieved when the expected number of days per year with concentrations above the standard is fewer than 1.

Note: Particulate matter (TSP) = total suspended particulate matter.

Particulate matter (PM10) = particulate matter with aerodynamic diameter less than or equal to 10 micrometers.

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

Sources: 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 that increases emissions by greater than significant amounts. PSD significant emission rates are shown in Table 3-2.

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

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

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

### 3.2.2 INCREMENTS/CLASSIFICATIONS

In promulgating the 1977 CAA Amendments, Congress specified that certain increases above an air quality baseline concentration level of SO<sub>2</sub> and total suspended particulate matter [PM(TSP)] concentrations would constitute significant deterioration. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications were designated, based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks,

Table 3-2. PSD Significant Emission Rates and De Minimis Monitoring Concentrations

Pollutant	Regulated Under	Significant Emission Rate (TPY)	<u>De Minimis</u> Monitoring Concentration <sup>a</sup> (µg/m <sup>3</sup> )
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 <sup>b</sup>
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Asbestos	NESHAP	0.007	NM
Beryllium	NESHAP	0.0004	0.001, 24-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Vinyl Chloride	NESHAP	1	15, 24-hour
Benzene	NESHAP	c	NM
Radionuclides	NESHAP	c	NM
Inorganic Arsenic	NESHAP	c	NM

<sup>a</sup> Short-term concentrations are not to be exceeded.

<sup>b</sup> No de minimis concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.

<sup>c</sup> Any emission rate of these pollutants.

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

NAAQS - National Ambient Air Quality Standards.

NM - No ambient measurement method.

NSPS - New Source Performance Standards.

NESHAP - National Emission Standards for Hazardous Air Pollutants.

µg/m<sup>3</sup> - micrograms per cubic meter.

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

national wilderness areas, and memorial parks larger than 5,000 acres, and national parks larger than 6,000 acres) or as Class II (all areas not designated as Class I). No Class III areas, which would be allowed greater deterioration than Class II areas, were designated. EPA then promulgated as regulations the requirements for classifications and area designations.

On October 17, 1988, EPA promulgated regulations to prevent significant deterioration as a result of emissions of  $\text{NO}_x$  and established PSD increments for  $\text{NO}_2$  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  $\text{SO}_2$ , PM(TSP), and  $\text{NO}_2$  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  $\text{SO}_2$  and PM(TSP) concentrations, or February 8, 1988, for  $\text{NO}_2$  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  $\text{SO}_2$  and PM(TSP)

concentrations, and after February 8, 1988, for NO<sub>2</sub> 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<sub>2</sub> and PM(TSP), and February 8, 1988, in the case of NO<sub>2</sub>.
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<sub>2</sub> and PM(TSP), and February 8, 1988, for NO<sub>2</sub>.

The minor source baseline date for SO<sub>2</sub> and PM(TSP) has been set as December 27, 1977, for the entire State of Florida (Chapter 17-2.450, F.A.C.).

### 3.2.3 CONTROL TECHNOLOGY REVIEW

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

05/01/91

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

An emissions limitation, including a visible emission standard, based on the maximum degree of reduction of each pollutant emitted which the department, on a case by case basis, taking into account energy, environmental, and economic impacts, and other costs, determines is achievable through application of production processes and available methods, systems, and techniques (including fuel cleaning or treatment or innovative fuel combustion techniques) for control of such pollutant. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular part of a source or facility would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement for the application of BACT. Such standard shall, to the degree possible, set forth the emissions reductions achievable by implementation of such design, equipment, work practice, or operation.

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



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

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

The top-down BACT approach essentially starts with the most stringent (or top) technology and emissions limit that have been applied elsewhere to the same or a similar source category. The applicant must next provide a basis for rejecting this technology in favor of the next most stringent technology or propose to use it. Rejection of control alternatives may be based on technical or economic infeasibility. Such decisions are made on the basis of physical differences (e.g., fuel type), locational differences (e.g., availability of water), or significant differences that may exist in the environmental, economic, or energy impacts. The differences between

the proposed facility and the facility on which the control technique was applied previously must be justified. Recently, EPA issued a draft guidance document on the top-down approach entitled Top-Down Best Available Control Technology Guidance Document (EPA, 1990).

#### 3.2.4 AIR QUALITY MONITORING REQUIREMENTS

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

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

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

### 3.2.5 SOURCE IMPACT ANALYSIS

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

Various lengths of record for meteorological data can be used for impact analysis. A 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 as a result of general commercial, residential, industrial, and other growth

associated with the source also must be addressed. These analyses are required for each pollutant emitted in significant amounts (Table 3-2).

### 3.2.7 GOOD ENGINEERING PRACTICE STACK HEIGHT

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

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

$$H_g = H + 1.5L$$

where:  $H_g$  = GEP stack height,

$H$  = Height of the structure or nearby structure, and

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

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

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

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

### 3.3 NONATTAINMENT RULES

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

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

### 3.4 SOURCE APPLICABILITY

#### 3.4.1 AREA CLASSIFICATION

The project site is located in Lake County, which has been designated by EPA and FDER as an attainment area for all criteria pollutants. Lake County and surrounding counties are designated as PSD Class II areas for SO<sub>2</sub>, PM(TSP), and NO<sub>x</sub>. The site is located 93 km from the closest part of the Chassahowitzka National Wilderness Area.

### 3.4.2 PSD REVIEW

#### 3.4.2.1 Pollutant Applicability

The proposed project is considered to be a major facility because emissions of any regulated pollutant will 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 NO<sub>x</sub>, CO, PM, and inorganic As. Therefore, the project is subject to PSD review for these pollutants.

#### 3.4.2.2 Ambient Monitoring

Based on the net increase in emissions from the proposed project, presented in Table 3-3, a PSD preconstruction ambient monitoring analysis is required for PM, NO<sub>x</sub>, CO, and As. However, if the net increase in impact of a pollutant is less than the de minimis monitoring concentration, then an exemption from the preconstruction ambient monitoring requirement is provided for in the FDER regulations [FDER Rule 17-2.500(3)(e)]. In addition, if an acceptable ambient monitoring method for the pollutant has not been established by EPA, monitoring is not required.

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

Maximum predicted impacts as a result of the net increase associated with the proposed project are presented in Table 3-4 for pollutants requiring PSD review. The methodology used to predict maximum impacts and the impact analysis results are presented in Sections 6.0 and 7.0. As shown in Table 3-4, the maximum net increase in impact is below the respective de minimis monitoring concentration for all pollutants. There is no acceptable ambient monitoring method for As; therefore, monitoring is not required for this pollutant.

Table 3-3. Net Increase in Emissions Due To the Lake County Cogeneration Facility Compared to the PSD Significant Emission Rates

Pollutant	Emissions (TPY)		PSD Review
	Potential Emissions From Proposed Turbines	Significant Emission Rate	
Sulfur Dioxide	21.0 <sup>b</sup>	40	No
Particulate Matter (TSP)	27.0	25	Yes
Particulate Matter (PM10)	27.0	15	Yes
Nitrogen Dioxide	404.7	40	Yes
Carbon Monoxide	466.5	100	Yes
Volatile Organic Compounds	30.8	40	No
Lead	0.0008	0.6	No
Sulfuric Acid Mist	0.8	7	No
Total Fluorides	0.003	3	No
Total Reduced Sulfur <sup>a</sup>	NEG	10	No
Reduced Sulfur Compounds <sup>a</sup>	NEG	10	No
Hydrogen Sulfide <sup>a</sup>	NEG	10	No
Asbestos <sup>a</sup>	NEG	0.007	No
Beryllium	0.0002	0.0004	No
Mercury	0.0003	0.1	No
Vinyl Chloride <sup>a</sup>	NEG	1	No
Benzene <sup>a</sup>	NEG	0	No
Radionuclides <sup>a</sup>	NEG	0	No
Inorganic Arsenic	0.0004	0	Yes

Note: NEG = Negligible.

All calculations based on 59°F peak load condition.

<sup>a</sup>Emissions of these pollutants considered not to have any emission rate increase.

<sup>b</sup>Based on a maximum sulfur content specification of 0.1 percent in fuel oil.

Table 3-4. Predicted Net Increase in Impacts Due To the Lake County Cogeneration Facility Compared to PSD De Minimis Monitoring Concentrations

Pollutant	Concentration ( $\mu\text{g}/\text{m}^3$ )	
	Predicted Net Increase In Impacts <sup>a</sup>	<u>De Minimis</u> Monitoring Concentration
Particulate Matter (TSP)	3.7 (1.3)	10, 24-hour
Particulate Matter (PM10)	3.7 (1.3)	10, 24-hour
Nitrogen Dioxide	0.33	14, annual
Carbon Monoxide	26.9 (25.0)	575, 8-hour
Inorganic Arsenic	NA	NM

Note: NA - Not applicable.

NM - No acceptable ambient measurement method has been developed and, therefore, de minimis levels have not been established by EPA.

<sup>a</sup> TSP and PM10 impacts based on maximum emissions at 100-percent load and 100-percent capacity factor when firing oil, which will be limited to no more than 10 days per year. Impacts for natural gas, the primary fuel shown in parenthesis. Concentrations indicate the highest predicted values.



#### 3.4.2.3 GEP Stack Height Impact Analysis

The GEP stack height regulations allow any stack to be at least 65 m high. The proposed stacks for the proposed turbines will be 100 feet (ft) in height (30.5 m) and, therefore, do not exceed the GEP stack height. The potential for downwash of the units' emissions caused by nearby structures is discussed in Section 6.0, Air Quality Modeling Approach.

#### 3.4.3 NONATTAINMENT REVIEW

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

#### 3.4.4 HAZARDOUS POLLUTANT REVIEW

The FDER has promulgated guidelines (FDER, 1991) to determine whether any emission of a hazardous or toxic pollutant can pose a possible health risk to the public. All regulated pollutants for which an ambient standard does not exist and all nonregulated hazardous pollutants are to be compared to No Threat Levels (NTL) for each applicable pollutant. If the maximum predicted concentration for any hazardous pollutant is less than the corresponding NTL for each applicable averaging time, that emission is considered not to pose a significant health risk.

#### 4.0 CONTROL TECHNOLOGY REVIEW

##### 4.1 APPLICABILITY

The control technology review requirements of the PSD regulations are applicable to emissions of NO<sub>x</sub>, CO, and inorganic As (see Section 3.0). This section presents the applicable NSPS and the proposed BACT for these pollutants. The approach to BACT analysis is based on the regulatory definitions of BACT, as well as EPA's current policy guidelines requiring the top-down approach.

##### 4.2 NEW SOURCE PERFORMANCE STANDARDS

The applicable NSPS for gas 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  $100 \times 10^6$  Btu/hr [40 CFR 60.332 (b)];
2. Stationary gas turbines with a heat input at peak load between 10 and  $100 \times 10^6$  Btu/hr [40 CFR 60.332 (c)]; or
3. Stationary gas turbines with a manufacturer's rate base load at ISO conditions of 30 MW or less [40 CFR 60.332 (d)].

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

As noted from Table 4-1, the NSPS NO<sub>x</sub> emission limit can be adjusted upward to allow for fuel-bound nitrogen (FBN). For a fuel-bound nitrogen concentration of 0.015 percent or less, no increase in the NSPS is provided; 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 <sup>a</sup>
Nitrogen Oxides <sup>b</sup>	0.0075 percent by volume (75 ppm) at 15 percent O <sub>2</sub> on a dry basis adjusted for heat rate and fuel nitrogen

<sup>a</sup> Applicable to electric utility gas turbines with a heat input at peak load of greater than  $100 \times 10^6$  Btu/hr.

<sup>b</sup> 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 <sub>x</sub> percent by volume
$N \leq 0.015$ .....	0
$0.015 < N \leq 0.1$ .....	$0.04(N)$
$0.1 < N \leq 0.25$ .....	$0.004 + 0.0067(N - 0.1)$
$N > 0.25$ .....	0.005

where:

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

Source: 40 CFR 60 Subpart GG.

For the proposed CTs, the NSPS emission limit would be 113 ppm corrected to 15 percent oxygen at a fuel-bound nitrogen content of 0.015 percent. The applicable NSPS for the duct burners will be 40 CFR 60, Subpart Db. The applicable requirements are presented in Table 4-2.

#### 4.3 BEST AVAILABLE CONTROL TECHNOLOGY

##### 4.3.1 NITROGEN OXIDES

##### 4.3.1.1 Identification of NO<sub>x</sub> Control Technologies for CTs

NO<sub>x</sub> emissions from combustion of fossil fuels consist of thermal NO<sub>x</sub> and fuel-bound NO<sub>x</sub>. Thermal NO<sub>x</sub> is formed from the reaction of oxygen and nitrogen in the combustion air at combustion temperatures. Formation of thermal NO<sub>x</sub> 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<sub>x</sub> is created by the oxidation of volatilized nitrogen in the fuel. Nitrogen content in the fuel is the primary factor in its formation.

Table 4-3 presents a listing of the lowest achievable emission rates/best available control technology (LAER/BACT) decisions made by state environmental agencies and EPA regional offices for gas turbines. 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<sub>x</sub> 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<sub>x</sub> 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

Table 4-2. Federal NSPS for Industrial Steam-Generating Units, 40 CFR 60, Subpart Db<sup>a</sup>

Pollutant	Emission Limitation for Gaseous or Liquid Fuels
Particulate Matter	Natural gas - no emission limits Oil - 0.10 lb/10 <sup>6</sup> Btu
Visible Emissions	20% opacity (6-minute average), except up to 27% opacity is allowed for one 6-minute period per hour
Sulfur Dioxide <sup>b</sup>	Natural gas - no emission limits Oil: 1) Annual capacity factor for oil > 30% - 0.80 lb/10 <sup>6</sup> Btu <u>and</u> 90% reduction in potential emissions 2) Annual capacity factor for oil < 30% <sup>c</sup> - 0.30 lb/10 <sup>6</sup> Btu (no percentage reduction requirements) 3) Combustion of 0.3 lb SO <sub>2</sub> /10 <sup>6</sup> Btu or less oil - 0.30 lb/10 <sup>6</sup> Btu - No percentage reduction requirements
Nitrogen Oxides	Natural gas/distillate oil: 1) Low heat release rate unit - 0.10 lb/10 <sup>6</sup> Btu 2) High heat release rate unit - 0.20 lb/10 <sup>6</sup> Btu 3) Duct burner in combined cycle system - 0.20 lb/10 <sup>6</sup> Btu  Residual oil: 1) Low heat release rate unit - 0.30 lb/10 <sup>6</sup> Btu 2) High heat release rate unit - 0.40 lb/10 <sup>6</sup> Btu 3) Duct burner in combined cycle system - 0.40 lb/10 <sup>6</sup> Btu

<sup>a</sup> Applies to any device that combusts fuel to produce steam and that has a maximum heat input of more than 100 x 10<sup>6</sup> Btu/hr. Sources subject to Subpart Da are not subject to Subpart Db.

<sup>b</sup> Compliance determined on a 30-day, rolling average basis (with certain exceptions).

<sup>c</sup> Includes combines cycle system where 30 percent or less of the heat input to the steam generator is from combustion of oil in the duct burner and 70 percent or more of the heat input is from the gas turbine exhaust gases entering the duct burner.

Source: 40 CFR 60, Subpart Db.

Table 4-3. 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 <sup>6</sup> BTU/hr	4/88	NO <sub>x</sub> 42 ppmvd at 15% O <sub>2</sub> (gas) NO <sub>x</sub> 77 ppmvd at 18% O <sub>2</sub> (fuel oil)	Steam injection with maximization NSPS Subpart GG
Trunkline LNG	LA	Gas turbine	147,102 scf/hr	5/87	NO <sub>x</sub> 59 lb/hr	
Wichita Falls E. I., I.	TX	Gas turbine	20 MW	6/86	NO <sub>x</sub> 684 TPY CO 420 TPY	Steam injection
Merck Sharp and Pohme	PA	Turbine	310x10 <sup>6</sup> Btu/hr	5/88	NO <sub>x</sub> 42 ppm at 15% O <sub>2</sub>	Steam injection
California Dept. of Corr.	CA	Gas turbine	5.1 MW	12/86	NO <sub>x</sub> 38 ppmv at 15% O <sub>2</sub>	1 to 1 H <sub>2</sub> O injection
City of Santa Clara	CA	Gas turbine		1/87	NO <sub>x</sub> 42 ppmvd at 15% O <sub>2</sub>	Water injection
Combined Energy Resources	CA	Cogeneration Fac.	27 MW	3/87	NO <sub>x</sub> 199 lb/day	SCR unit, duct burner, H <sub>2</sub> O injection, low NO <sub>x</sub> design
Double 'C' Limited	CA	Gas turbine	25 MW	11/86	NO <sub>x</sub> 194 lb/day	H <sub>2</sub> O injection and SCR 95.80 efficiency
Kern Front Limited	CA	Gas turbine	25 MW	11/86	NO <sub>x</sub> 194 lb/day 4.5 ppmvd at 15% O <sub>2</sub>	H <sub>2</sub> O injection and SCR 95.80 efficiency
Midway - Sunset Project	CA	Gas turbine	973x10 <sup>6</sup> Btu/hr	1/87	NO <sub>x</sub> 113.4 lb/hr 16.31 ppmv	H <sub>2</sub> O injection, 73% efficiency
O'Brien Energy Systems	CA	Gas turbine	359.5x10 <sup>6</sup> Btu/day	12/86	NO <sub>x</sub> 30.3 lb/hr 15 ppmvd at 15% O <sub>2</sub>	Duct burner, H <sub>2</sub> O injection and scrubber
PG and E, Station T	CA	GE gas turbine	396x10 <sup>6</sup> Btu/hr	8/86	NO <sub>x</sub> 25 ppm at 15% O <sub>2</sub> 63 lb/hr	Steam injection at steam/fuel ratio of 1.7/1, 75% efficiency
Sierra LTD.	CA	GE gas turbine	11.34x10 <sup>6</sup> ft <sup>3</sup> /day		NO <sub>x</sub> 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 <sub>2</sub> 3 hr average	CO oxidizing catalyst combustion control
U.S. Borax and Chemical Corp.	CA	Gas turbine	45 MW	2/87	NO <sub>x</sub> 40 lb/hr 25 ppm at 15% O <sub>2</sub> Dry CO 23 lb/hr	Scrubber Proper combustion techniques
Western Power System, Inc	CA	GE gas turbine	26.5 MW	3/86	NO <sub>x</sub> 9 ppmvd at 15% O <sub>2</sub>	H <sub>2</sub> O injection, SCR 80% efficiency
Calcogen, Cal Polytechnic	CA	Gas turbine	21.4 MW	4/84	NO <sub>x</sub> 42 ppm at 15% O <sub>2</sub>	H <sub>2</sub> O injection, 70% efficiency

Table 4-3. 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	GE gas turbine	35.62 MW	4/85	NO <sub>x</sub> 42 ppm at 15% O <sub>2</sub> 91 lb/hr CO 20.41 lb/hr 0.016 lb/10 <sup>6</sup> Btu	H <sub>2</sub> O injection Good Engineering Practices Steam injection 95.86 efficiency
Greenleaf Power Co.	CA	Duct Burner	63.7x10 <sup>6</sup> Btu/hr	4/85	NO <sub>x</sub> 0.1 lb/10 <sup>6</sup> Btu 6.4 lb/hr CO 0.12 lb/10 <sup>6</sup> Btu 7.6 lb/hr	Low NO <sub>x</sub> design
OLS Energy	CA	GE gas turbine	256x10 <sup>6</sup> Btu/hr	1/86	NO <sub>x</sub> 9 ppmvd at 15% O <sub>2</sub>	H <sub>2</sub> O injection and scrubber 80% efficiency for scrubber
Ciba Giegy Corp.	NJ	Gas turbine	3 MW	1/85	NO <sub>x</sub> 11.06 lb/hr CO 9.4 lb/hr	SIP, H <sub>2</sub> O injection, 55% efficiency
Energy Reserve, Inc.	CA	Gas turbine	322.5x10 <sup>6</sup> Btu/hr	10/85	NO <sub>x</sub> 185.4 lb/day	H <sub>2</sub> O injection, SCR 92.5% efficiency
Gilroy Energy Co.	CA	Gas turbine	60 MW	8/85	NO <sub>x</sub> 25 ppmvd at 15% O <sub>2</sub>	Steam injection, quiet combustor
		Auxiliary boiler	90x10 <sup>6</sup> Btu/hr		NO <sub>x</sub> 40 ppmvd at 3% O <sub>2</sub>	Low NO <sub>x</sub> burners
Kern Energy Corp.	CA	Gas turbine	8.8x10 <sup>6</sup> ft <sup>3</sup> /day	4/86	NO <sub>x</sub> 8.29 lb/hr 0.023 lb/10 <sup>6</sup> Btu	Scrubber with NH <sub>3</sub> reduction agent Steam injection and low NO <sub>x</sub> configuration exhaust duct burner 87% efficiency
Moran Power, Inc.	CA	Gas turbine	8.0x10 <sup>6</sup> ft <sup>3</sup> /day	4/86	NO <sub>x</sub> 8.29 lb/hr 0.023 lb/10 <sup>6</sup> Btu	Scrubber with NH <sub>3</sub> reduction agent Steam injection and low NO <sub>x</sub> configuration exhaust duct burner 87% efficiency
Northern California Power	CA	GE gas turbine	25.8 MW	4/85	NO <sub>x</sub> 75 ppm	H <sub>2</sub> O injection
Shell California Production	CA	Gas turbine	22 MW	4/85	NO <sub>x</sub> 42 ppm at 15% O <sub>2</sub> 35 lb/hr CO 10 ppmv at 15% O <sub>2</sub> 22 lb/hr	H <sub>2</sub> O injection Proper combustion
Southeast Energy, Inc.	CA	Gas turbine	8.0x10 <sup>6</sup> ft <sup>3</sup> /day	4/86	NO <sub>x</sub> 8.29 lb/hr 0.023 lb/10 <sup>6</sup> Btu	Scrubber with NH <sub>3</sub> reduction agent Steam injection and low NO <sub>x</sub> configuration exhaust duct burner 87% efficiency
Sunlaw/Industrial Park	CA	Gas turbine	412.3x10 <sup>6</sup> Btu/hr	6/85	NO <sub>x</sub> 9 ppmvd at 15% O <sub>2</sub>	Scrubber and steam injection, 80% efficiency
Union Cogeneration	CA	Gas turbine with Duct burner	16 MW	1/86	NO <sub>x</sub> 25 ppmv at 15% O <sub>2</sub>	H <sub>2</sub> O injection and scrubber

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

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
Willamette Industries	CA	GE gas turbine	230x10 <sup>6</sup> Btu/hr	4/85	NO <sub>x</sub> 15 ppmvd at 15% O <sub>2</sub>	H <sub>2</sub> O injection with SCR 92% efficiency
Witco Chemical Corp.	CA	Gas turbine	350x10 <sup>6</sup> Btu/hr	12/84	NO <sub>x</sub> 0.18 lb/10 <sup>6</sup> Btu oil 0.20 lb/10 <sup>6</sup> Btu gas	
		Duct burner	111.6x10 <sup>6</sup> Btu/hr		NO <sub>x</sub> 0.12 lb/10 <sup>6</sup> Btu	Gas firing only
AES Placerita, Inc.	CA	Turbine and Recovery Boiler	519x10 <sup>6</sup> Btu/hr	3/86	NO <sub>x</sub> 629 lb/day 7 ppmvd at 15% O <sub>2</sub> CO 103 lb/day 2 ppmvd at 15% O <sub>2</sub>	H <sub>2</sub> O injection, SCR 80% efficiency
AES Placerita, Inc.	CA	Turbine and Recovery Boiler	530x10 <sup>6</sup> Btu/hr	7/87	NO <sub>x</sub> 340 lb/day 9 ppmvd at 15% O <sub>2</sub>	Steam injection, SCR
AES Placerita, Inc.	CA	Gas turbine	530x10 <sup>6</sup> Btu/hr	7/87	NO <sub>x</sub> 289 lb/day 9 ppmvd at 15% O <sub>2</sub>	Steam injection, SCR
Alaska Electrical Generation	AK	Gas turbine	80 MW	3/87	NO <sub>x</sub> 75 ppmvd at 15% O <sub>2</sub> CO 109 lb/scf fuel	H <sub>2</sub> O injection
Alaska Electrical Generation	AK	Gas turbine	38 MW	3/85	NO <sub>x</sub> 75 ppm at 15% O <sub>2</sub>	H <sub>2</sub> O injection
BAF Energy	CA	Turbine, Generator	887.2x10 <sup>6</sup> Btu/hr	7/87	NO <sub>x</sub> 9 ppm at 15% O <sub>2</sub> 30.1 lb/hr	Steam injection, scrubber 80% efficiency
BAF Energy	CA	Auxiliary Boiler	150x10 <sup>6</sup> Btu/hr	10/87	NO <sub>x</sub> 17.4 lb/day 40 ppmvd at 3% O <sub>2</sub> CO 63.6 lb/day 0.018 lb/10 <sup>6</sup> Btu	Flue gas recirculation Low NO <sub>x</sub> burners Oxidation catalyst
Champion International Corp.	TX	Gas turbine	30.6 MW (1,342x10 <sup>6</sup> Btu/hr)	3/85	NO <sub>x</sub> 720.34 TPY CO 70.08 TPY	Low NO <sub>x</sub> burners
Cogen Technologies	NJ	GE gas turbines	40 MW	6/87	NO <sub>x</sub> 9.6 ppmvd at 15% O <sub>2</sub> CO 50 ppmvd at 15% O <sub>2</sub>	H <sub>2</sub> O injection and SCR, 95% efficiency
Combined Energy Resources	CA	Gas turbine	2 MW	2/88	NO <sub>x</sub> 199 lb/hr	H <sub>2</sub> O injection and scrubber, 81% efficiency
Formosa Plastic Corp.	TX	GE gas turbine	38.4 MW	5/86	NO <sub>x</sub> 640 TPY CO 32.4 TPY	Steam injection
Midland Cogeneration Venture	MI	Turbine	984.2x10 <sup>6</sup> Btu/hr	2/88	NO <sub>x</sub> 42 ppmv at 15% O <sub>2</sub> CO 26 lb/hr	Steam injection Turbine design
		Duct burner	249x10 <sup>6</sup> Btu/hr		NO <sub>x</sub> 0.1 lb/10 <sup>6</sup> Btu	Burner design



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

Company Name	State	Unit Description	Capacity (Size)	Date of Permit	Emission Limit	Emission Control
Pacific Gas Transmission	OR	Gas turbine	14,000 HP	5/87	NO <sub>x</sub> 154 ppm 50 lb/hr CO 6 lb/hr 25 TPY	Combustion control
Power Development Co.	CA	Gas turbine	49x10 <sup>6</sup> Btu/hr	6/87	NO <sub>x</sub> 36 lb/day 9 ppmvd at 15% O <sub>2</sub>	Scrubber and H <sub>2</sub> O injection
San Joaquin Cogen Limited	CA	Gas turbine	48.6 MW	6/87	NO <sub>x</sub> 250 lb/day 6 ppmvd at 15% O <sub>2</sub> CO 1326 lb/day 55 ppmvd at 15% O <sub>2</sub>	Scrubber and H <sub>2</sub> O injection 76% efficiency Combustion controls
United Airlines	CA	Gas turbine-Cogeneration	21 MW	12/85	NO <sub>x</sub> 15 ppmvd at 15% O <sub>2</sub>	SCR and steam injection Oil limited to 500 hours operation
TBG/Grumman	NY	Gas turbine	16 MW	3/88	NO <sub>x</sub> 75 ppm + NSPS Corr. 0.2 lb/10 <sup>6</sup> Btu CO 0.181 lb/10 <sup>6</sup> Btu	H <sub>2</sub> O injection and combustion controls CO catalyst
Texas Gas Transmission Corp.	KY	Gas turbine	14,300 HP	2/88	NO <sub>x</sub> 0.015% by Volume	
Orlando Utilities Commission	FL	Gas turbine	4 x 445x10 <sup>6</sup> Btu/hr	9/88	NO <sub>x</sub> 42 ppmvd Gas 65 ppmvd Oil CO 10 ppmvd	Steam injection Good combustion
Anheuser-Busch	FL	Gas turbine	95.7x10 <sup>6</sup> Btu/hr	4/87	NO <sub>x</sub> 0.1 lb/10 <sup>6</sup> Btu	
Ocean State Power	RI	Combined Cycle	500 MW	1/89	NO <sub>x</sub> 9 ppmvd at 15% O <sub>2</sub> (Natural Gas) NO <sub>x</sub> 42 ppmvd at 15% O <sub>2</sub> (fuel oil) CO 25 ppmvd at 15% O <sub>2</sub>	SCR and steam injection
Pawtucket Power	RI	Cogeneration-Gas turbine	58 MW	2/89	NO <sub>x</sub> 9 ppmvd at 15% O <sub>2</sub> (natural gas) NO <sub>x</sub> 18 ppmvd at 15% O <sub>2</sub> (fuel oil) CO 23 ppmvd at 15% O <sub>2</sub>	SCR and steam injection
Cogen Technologies	NJ	Gas turbine	55 MW	3/87	NO <sub>x</sub> 9 ppmvd at 15% O <sub>2</sub> (natural gas) NO <sub>x</sub> 14 ppmvd at 15% O <sub>2</sub> (fuel oil) CO 8 ppm; 20 ppm NH <sub>3</sub>	SCR and wet injection

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<sub>2</sub> nonattainment 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 previously, 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 generally is restricted by permit to 1,000 hours per CT or less.

Reported and permitted NO<sub>x</sub> 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<sub>x</sub> levels below 42 ppm. For fuel oil firing, permitted NO<sub>x</sub> emission limits with SCR have ranged from 14 ppm to 42 ppm. SCR has not been installed or permitted on simple cycle CTs.

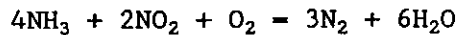
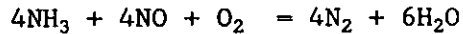
Wet injection is the primary method of reducing NO<sub>x</sub> emissions from CTs. This method of control was first mandated by the NSPS to reduce NO<sub>x</sub> levels to 75 parts per million by volume, dry (ppmvd) (corrected to 15 percent O<sub>2</sub> and heat rate). Development of improved wet injection combustors reduced NO<sub>x</sub> concentrations to 25 ppmvd and 42 ppmvd (corrected to 15 percent O<sub>2</sub>) when burning natural gas and fuel oil, respectively. Recently, CT manufacturers have developed dry low NO<sub>x</sub> combustors that can reduce NO<sub>x</sub> concentrations to 25 ppmvd (corrected to 15 percent O<sub>2</sub>) 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<sub>x</sub> control. The emission limits included in these permits and BACT determinations were 42 ppm and 65 ppm (corrected to 15 percent O<sub>2</sub>, dry conditions), respectively, for natural gas and fuel oil firing. In November 1990, FDER determined that a CT using a dry low NO<sub>x</sub> combustor to reduce NO<sub>x</sub> 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<sub>3</sub>) to react with NO<sub>x</sub> in the gas stream in the presence of a catalyst. NH<sub>3</sub>, which is diluted with air to about 5 percent by volume, is introduced into the gas stream at

reaction temperatures between 600°F and 750°F. The reactions are as follows:



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 generally are in the range of 1,000°F, which exceeds the optimum range for SCR. All current SCR applications have the catalyst placed in the HRSG to achieve proper reaction conditions. This allows a relatively constant temperature for the reaction of  $\text{NH}_3$  and  $\text{NO}_x$  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 4-4. 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 was 500 hours. Currently, the facility does not operate on fuel oil.

As presented in Table 4-4, ammonium salts (ammonium sulfate and bisulfate) are formed by the reaction of  $\text{NH}_3$  and sulfur combustion products. 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. Ammonium sulfate is emitted as particulate matter.

Table 4-4. Cost, Technical, and Environmental Considerations of SCR Used 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 $\text{NH}_3$ to $\text{NO}_x$ 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.
Electrical	Additional usage of energy to operate ammonia pumps and dilution fans.
TECHNICAL:	
Ammonia Flow Distribution	$\text{NH}_3$ must be uniformly distributed in the exhaust stream to assure optimum mixing with $\text{NO}_x$ 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	Quantity of $\text{NH}_3$ introduced must be carefully controlled. With too little $\text{NH}_3$ , the desired control efficiency is not reached; with too much $\text{NH}_3$ , $\text{NH}_3$ emissions (referred to as slip) occur.

Table 4-4. Cost, Technical, and Environmental Considerations of SCR Used 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 <sub>3</sub> slip (NH <sub>3</sub> 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 4) the proper temperature is not maintained.
Ammonium Salts	Ammonium salts (ammonium sulfate and bisulfate) can lead to increased corrosion. These salts usually occur when firing fuel oil. These compounds are emitted as particulates.

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. 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).

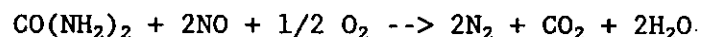
Wet Injection--The injection of water or steam in the combustion zone of CTs reduces the flame temperature with a corresponding decrease of NO<sub>x</sub> emissions. The amount of NO<sub>x</sub> reduction possible depends on the combustor design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO<sub>x</sub> 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 project, the combustion chamber design includes the use of water injection. This combustor allows an increase in the amount of steam or water injected into the combustion zone while reducing the impacts of incomplete combustion. The lowest NO<sub>x</sub> emission level guaranteed by GE for the LM 6000 is 25 ppmvd (corrected to 15 percent O<sub>2</sub>) when firing natural gas and 42 ppmvd (corrected to 15 percent O<sub>2</sub>) when firing fuel oil.

Dry Low NO<sub>x</sub> Combustor--In the past several years, CT manufacturers have offered and installed machines with dry low NO<sub>x</sub> combustors. These combustors, which are offered on machines manufactured by GE, Kraftwerk Union, and Asea Brown Boveri (ABB), can achieve NO<sub>x</sub> concentrations of

25 ppmvd or less when firing natural gas. Thermal NO<sub>x</sub> formation is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition. However, when firing oil, NO<sub>x</sub> emissions are controlled only through water or steam injection to exhaust concentrations of 65 ppmvd. Dry low NO<sub>x</sub> combustors have not been developed for the aircraft-derivative CTs, such as the GE LM 6000 proposed for the project.

NO<sub>x</sub>OUT Process--The NO<sub>x</sub>OUT process originated from the initial research by the Electric Power Research Institute (EPRI) in 1976 on the use of urea to reduce NO<sub>x</sub>. EPRI licensed the proprietary process to Fuel Tech, Inc., for commercialization. In the NO<sub>x</sub>OUT 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:



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<sub>x</sub>. 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 as follows:

1. Low capital and operating costs as a result of use of urea injection, and
2. The proprietary catalysts used are nontoxic and nonhazardous, thus eliminating potential disposal problems.

Disadvantages of the system are as follows:

1. Formation of ammonia from excess urea treatment rates and/or improper use of reagent catalysts, and
2. SO<sub>3</sub>, 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<sub>x</sub>OUT 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<sub>x</sub> reduction,
2. A 600 x 10<sup>6</sup> Btu CO boiler with 60 to 70 percent NO<sub>x</sub> reduction, and
3. A 75-MW pulverized coal-fired unit with 65 percent NO<sub>x</sub> reduction.

The NO<sub>x</sub>OUT system has not been demonstrated on any combustion turbine/HRSG unit.

The NO<sub>x</sub>OUT process is not technically feasible for the proposed project because of 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<sub>x</sub>.

Thermal DeNO<sub>x</sub>--Thermal DeNO<sub>x</sub> is Exxon Research and Engineering Company's patented process for NO<sub>x</sub> reduction. The process is a high temperature selective noncatalytic reduction (SNCR) of NO<sub>x</sub> using ammonia as the reducing agent. Thermal DeNO<sub>x</sub> 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 before ammonia injection.

The only known commercial applications of Thermal DeNO<sub>x</sub> 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 piping and components since the exhaust gas volume would be increased by several times. As with the NO<sub>x</sub>OUT

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<sub>x</sub> process will not be considered for the proposed project since its high application temperature makes it technically infeasible. The exhaust gas temperature of a combustion turbine is typically about 850°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<sub>x</sub> 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 have 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<sub>x</sub> control device for CTs.

Duct Firing--The proposed control technology for duct firing will be the use of low NO<sub>x</sub> burners that will limit the emissions to 0.1 lb/10<sup>6</sup> Btu heat input. This proposed limit is the lowest being permitted for similar facilities and is one-half the NSPS limit.

Summary of Technically Feasible NO<sub>x</sub> Control Methods--The available information suggests that SCR with wet injection is technically feasible for the project.

A technical evaluation of tail gas controls (i.e., SCR, NO<sub>x</sub>OUT, Thermal DeNO<sub>x</sub>, and NSCR) indicates that these processes have not been applied to CTs/HRSGs and are technically infeasible for the project because of process constraints (e.g., temperature). Dry low NO<sub>x</sub> combustors are inappropriate

for the project since they are unavailable for the aircraft-derivative machine.

Wet injection is a technically feasible alternative for the project. 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 25 ppm with natural gas and 42 ppm with fuel oil (corrected to 15 percent oxygen, dry conditions).
2. Wet injection will not reduce substantially  $\text{NO}_x$  formation caused by fuel-bound nitrogen. Fuel quality will limit the formation of fuel-bound  $\text{NO}_x$ .
3. Wet injection will increase the emissions of CO and VOC.  
Emissions are dependent on the water-to-fuel ratio.

For the BACT analysis, SCR and wet injection capable of achieving  $\text{NO}_x$  emission levels to 25 ppm when firing natural gas and 42 ppm when firing fuel oil (corrected to 15 percent  $\text{O}_2$  dry conditions) was assumed.

#### 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 the following alternatives:

1. SCR and wet injection at an emission rate of approximately 9 ppmvd corrected to 15 percent  $\text{O}_2$ ; maximum  $\text{NO}_x$  emissions are 142 TPY.
2. Wet injection at an emission rate of 25 ppmvd corrected to 15 percent  $\text{O}_2$ ; maximum  $\text{NO}_x$  emissions are 405 TPY.

Economic--The total capital and annualized costs for the alternative  $\text{NO}_x$  control technologies are presented in Tables 4-5 and 4-6, respectively.

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 1 of 2)

Cost Component	Estimated Cost (\$)	Basis for Cost Estimate
<u>Direct Capital Costs</u>		
SCR Associated Equipment	575,700	Developed from manufacturer budget quotations
Ammonia Storage Tank	150,000	Developed from manufacturer budget quotations
HRSG Modification	264,000	Developed from manufacturer budget quotations
<u>Indirect Capital Costs</u>		
Installation	374,300	20% of SCR associated equipment and ammonia storage tank
Engineering, Erection Supervision, Startup, and O&M Training	298,400	10% SCR equipment and catalyst, ammonia storage tank and HRSG costs
Project Support	164,100	5% SCR equipment and catalyst, ammonia storage tank, HRSG and engineering costs
Ammonia Emergency Preparedness Program	19,200	Engineering estimate
Liability Insurance	16,400	0.5% SCR equipment and catalyst, ammonia storage tank, HRSG and engineering costs
Interest During Construction	614,500	15% of all direct and indirect capital costs including catalyst cost
Contingency	558,400	25% of all capital costs
<u>Total Capital Costs</u>	3,035,100	Sum of all capital costs
<u>Annualized Capital Costs</u>	356,500	Capital recovery of 10% over 20 years, 11.74% per year
<u>Recurring Capital Costs</u>		
SCR Catalyst (Materials and Labor)	1,296,000	Developed from manufacturer budget quotations

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 2 of 2)

Cost Component	Estimated Cost (\$)	Basis for Cost Estimate
Contingency	324,000	25% of recurring capital costs
<u>Total Recurring Capital Costs</u>	1,620,000	Sum of recurring capital costs
<u>Annualized Recurring Capital Costs</u>	651,400	Capital recovery of 10% over 3 years, 40.21% per year

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR)  
(Page 1 of 2)

Cost Component	Estimated Cost (\$)	Basis for Cost Estimate
<u>Direct Annual Costs</u>		
Operating Personnel	20,800	16 hours/week @ \$25/hour
Ammonia	29,200	\$300/ton; $\text{NH}_3:\text{NO}_x = 1:1$ volume
Accident/Emergency Response Plan	8,100	Consultant estimate, 80 hours/year @ \$75/hour plus expenses @ 35% labor
Inventory Cost	50,700	Capital recovery (11.74%/year) for 1/3 of catalyst cost
Catalyst Disposal Cost	60,000	Engineering estimate
Contingency	50,900	25% of indirect costs
<u>Energy Costs</u>		
Electrical	70,100	80 kwh/hr; \$0.05/KWH
Heat Rate Penalty	184,200	4" back pressure, heat rate reduction of 0.5%, energy loss at \$0.05/KWH
MW Loss Penalty	137,300	84 MW lost for 3 days; lost capacity @ \$0.05/KW; cost of natural gas @ \$3/MMBtu subtracted
Fuel Escalation Costs	115,600	Real cost increase of fuel
Contingency	92,400	25% of energy costs; excludes fuel escalation
<u>Total Direct Annual Costs</u>	819,300	Sum of all direct annual costs
<u>Indirect Annual Costs</u>		
Overhead	35,000	60% of ammonia plus 115% of O&M labor; plus 15% of O&M labor (OAQPS Cost Control Manual)
Property Taxes and Insurance	93,100	2% of total capital costs
Annualized Capital Costs	356,500	Capital recovery of 10% over 20 years, 11.74% per year
Recurring Capital Costs	651,400	Capital recovery of 10% over 3 years, 40.21% per year

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR)  
(Page 2 of 2)

Cost Component	Estimated Cost (\$)	Basis for Cost Estimate
<u>Total Indirect Annual Costs</u>	1,136,000	Sum of all indirect annual costs
<u>Total Annual Costs</u>	1,955,300	Total annualized cost

Note: All calculations rounded off to the nearest \$100.

\*Based on 100% capacity factor; 65% removal of NO<sub>x</sub>.

The total annualized cost is \$1,955,262. The cost effectiveness for SCR was estimated to be greater than \$7,000/ton of NO<sub>x</sub> removed for the project.

Environmental--The maximum predicted impacts of the alternative technologies are all considerably below the PSD increment for NO<sub>x</sub> of 25 µg/m<sup>3</sup>, annual average, and the AAQS for NO<sub>x</sub>, 100 µg/m<sup>3</sup>. Indeed, the impacts are less than the significant impact levels. Additional controls beyond steam injection alone (i.e., SCR and SCR with water injection) would further reduce predicted impacts by much less than 1 percent of the PSD increment and the AAQS for the project.

Use of SCR on the proposed project will cause emissions of ammonia and ammonium salts, such as ammonium sulfate and bisulfate. Ammonia emissions associated with SCR are expected to be 10 ppm and higher based on reported experience; previous permit conditions have specified this level. Ammonia emissions could be about 57 TPY. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM<sub>10</sub>; up to 43 TPY could be emitted.

The electrical energy required to run the SCR system and the back pressure from the turbine will generate secondary emissions since this lost energy will necessitate additional generation. These emissions, coupled with potential emissions of ammonia and ammonium salts are presented in Table 4-7, which shows the emissions balance for the project with and without SCR. Emissions of carbon dioxide were included in this table, since this gas is under study as required in the 1990 Clean Air Act Amendments. As noted from this table, the total emissions with SCR would be greater than that proposed.

The replacement of the SCR catalyst will create additional economic and environmental impacts since certain catalysts contain materials that are listed as hazardous chemical wastes under Resource Conservation and Recovery Act (RCRA) regulations (40 CFR 261).



Table 4-7. Maximum Potential Emissions Differentials With and Without Selective Catalytic Reduction (SCR)

Pollutants	With SCR			Project Without SCR	Difference (with-w/out)
	Primary	Secondary*	Total	CT/DB	
Particulate	43	2.54	46	0	46
Sulfur Dioxide	0	27.94	28	0	28
Nitrogen Oxides	142	13.97	156	405	(249)
Carbon Monoxide	0	0.84	1	0	1
Volatile Organic Compounds	0	0.13	0	0	0
Ammonia	57	0.00	57	0	57
Total Emissions:	243	45.42	288	405	(117)
Carbon Dioxide	0	4,362	4,362	0	4,362

\* EPA emission factors used for 1% sulfur fuel oil and an assumed heat rate of 10,000 Btu/kWh.  
Lost energy of 0.58 MW for 8,760 hours per year operation.

Ammonia delivery and storage must be handled with caution because of its hazardous nature. Special precautions would be required to assure that no environmental discharge occurs.

Energy--Energy penalties will occur with all control alternatives evaluated. However, significant energy penalties occur with SCR. With SCR, the output of the CT is reduced by about 0.50 percent over that of wet injection. This penalty is the result of the SCR pressure drop, which would be about 4 inches of water and would amount to about 3,850,000 kilowatt hours (kWh) in potential lost generation per year. The energy required by the SCR equipment would be about 1,401,600 kilowatt hours per year (kWh/yr). Taken together, the lost generation and energy requirements of SCR could supply the electrical needs of 400 residential customers. To replace this lost energy, an additional  $5.3 \times 10^{10}$  British thermal units per year (Btu/yr) or about 53 million ft<sup>3</sup>/yr of natural gas would be required.

Technology Comparison--Since the purpose of the project is to produce electrical energy, and combustion turbine technology is rapidly advancing, it is appropriate to compare the proposed emissions on an equivalent generation basis to that of both the advanced and conventional CTs. The heat rate of the LM 6000 will be 9,112 Btu/kWh or better at ISO conditions (see Table A-1 in Appendix A). In contrast, heat rates for the conventional Frame 6 and the advanced CT are about 11,000 Btu/kWh and 9,600 Btu/kWh, respectively. The NO<sub>x</sub> emission rates of the LM 6000 and advanced CTs, relative to the heat rate and NO<sub>x</sub> emission rate of conventional CTs at 25 ppmvd corrected, are as follows:

LM 6000 CT - 20.6 ppmvd corrected to 15 percent O<sub>2</sub>

Advanced CT\* - 21.8 ppmvd corrected to 15 percent O<sub>2</sub>

Conventional CT - 25 ppmvd corrected to 15 percent O<sub>2</sub>

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\*Dry low NO<sub>x</sub> combustor.

As shown, the LM 6000 will emit less NO<sub>x</sub> on a MW-generated basis than the advanced CT.

#### 4.3.1.4 Proposed BACT and Rationale

The proposed BACT for the project is wet injection. The proposed NO<sub>x</sub> emissions levels using wet injection are 25 ppm when firing natural gas and 42 ppm when firing fuel oil. This control technology is proposed for the following reasons:

1. SCR was rejected based on technical, economic, environmental, and energy grounds. The estimated incremental cost of SCR for natural gas firing exceeds \$7,000 per ton of NO<sub>x</sub> removed. These costs are in the range for other projects that have rejected SCR as unreasonable. Additional environmental impacts would result from SCR operation, including emissions of ammonia; from secondary generations (to replace the lost generation); and from the generation of hazardous waste (i.e., spent catalyst replacement). The energy impacts of SCR will reduce generation by more than 5 million kWh. The NO<sub>x</sub> emissions will be the lowest on an MW basis than any permitted CT without SCR.
2. The proposed BACT of wet injection provides the least costly control alternative and results in low environmental impacts (approximately 1 percent of the allowable PSD increments and less than 1 percent of the AAQS for NO<sub>x</sub>). Wet injection at the proposed emissions levels has been adopted previously in BACT determinations. In addition, CT manufacturers have been willing to guarantee this level of NO<sub>x</sub> emissions.

#### 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<sub>x</sub> 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<sub>x</sub> control, CO emissions will not exceed 42 ppm, corrected to dry conditions when firing natural gas and 78 ppm when firing fuel oil. These emission limits are based on calculated CO levels with margins added to account for the lack of operating experience with the LM 6000. Actual emissions under full-load conditions are expected to be less than one-half of those presented in this application.

Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels to be less than those associated with wet injection. These installations have been required to use 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 primarily have been limited to smaller cogeneration facilities burning natural gas.

Oxidation catalysts have not been used on fuel-oil-fired CTs or combined cycle facilities. The use of sulfur-containing fuels in an oxidation

catalyst system would result in an increase of SO<sub>2</sub> 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 project, the following alternatives were evaluated for natural gas firing as BACT:

1. Oxidation catalyst at 10 ppmvd; maximum annual CO emissions are 117 TPY;
2. Combustion controls at 75 percent control; maximum annual CO emissions are 467 TPY.

#### 4.3.2.3 Impact Analysis

Economic--The estimated annualized cost of a CO oxidation catalyst is \$968,120 (Table 4-8), with a cost effectiveness of about \$2,800/ton of CO removed. The cost effectiveness is based on 75 percent efficiency (42 ppmvd to 10 ppmvd). No costs are associated with combustion techniques since they are inherent in the design.

Table 4-8. Capital and Annualized Cost for Oxidation Catalyst

Cost Component	Cost (\$)	Basis
<b>I. CAPITAL COSTS</b>		
<b>A. DIRECT:</b>		
1. Associated Equipment for Catalyst	157,500	Manufacture Estimate - \$1,750 per lb/sec mass flow
2. Exhaust Modification	150,000	Engineering Estimate - \$75,000/CT
3. Installation	300,000	25% of Equipment Costs (I.A.1. & 2., and II.A.)
<b>B. INDIRECT:</b>		
1. Engineering & Supervision	90,000	7.5% of Equipment Costs (I.A.1. & 2., and II.A.)
2. Construction and Field Expense	120,000	10% of Equipment Costs (I.A.1. & 2., and II.A.)
3. Construction Contractor Fee	60,000	5% of Equipment Costs (I.A.1. & 2., and II.A.)
4. Startup & Testing	24,000	2% of Equipment Costs (I.A.1. & 2., and II.A.)
5. Contingency	225,375	25% of Direct and Indirect Capital Costs (I.A. and I.B.1-4)
6. Interest During Construction	302,906	15% of Direct and Indirect Capital Costs, and Recurring Capital Costs (I.A., I.B.1.-4 and II.A.)
<b>TOTAL CAPITAL COSTS</b>	<b>1,429,781</b>	<b>Sum of Direct and Indirect Capital Costs</b>
<b>ANNUALIZED CAPITAL COSTS</b>	<b>167,942</b>	<b>Capital Recovery of 10% over 20 years</b>
<b>II. RECURRING CAPITAL COSTS</b>		
<b>A. Catalyst</b>		
	892,500	Manufacture Estimate - \$1,750 per lb/sec mass flow
<b>B. Contingency</b>		
	223,125	25% of Recurring Capital Costs (II.A)
<b>TOTAL RECURRING CAPITAL COSTS</b>	<b>1,115,625</b>	<b>Sum of Recurring Capital Costs</b>
<b>ANNUALIZED RECURRING CAPITAL COSTS</b>	<b>448,609</b>	<b>Capital Recovery of 10% over 20 years</b>
<b>III. ANNUALIZED COST</b>		
<b>A. DIRECT:</b>		
1. Labor - Operator & Supervisor	5,262	4 hours/week, 52 weeks/year, \$22/hour and 15% supervisor cost
2. Maintenance	12,727	0.5% of Total and Recurring Capital Costs
3. Inventory Cost	17,472	Capital Carrying cost (10% over 20 years) for catalyst for 1 CT
<b>B. ENERGY COSTS</b>		
1. Heat Rate Penalty	77,165	0.2% heat rate penalty. \$50/MW energy loss
2. MW Loss Penalty (catalyst changeout)	50,554	Loss of 84 MW for one day; cost of natural gas at \$3/10 <sup>6</sup> Btu deducted from cost
3. Fuel Escalation Costs	35,079	Fuel escalation of 3% over inflation; annualized over 20 years
4. Contingency	40,699	25% of energy costs
<b>C. INDIRECT:</b>		
1. Overhead	10,794	60% of Labor and Maintenance Costs (III.A.1. and 2.)
2. Property Taxes	25,454	1% of Total and Recurring Capital Cost
3. Insurance	25,454	1% of Total and Recurring Capital Cost
4. Administration	50,908	2% of Total and Recurring Capital Cost
<b>Annualized Capital Costs</b>	<b>167,942</b>	
<b>Annualized Recurring Capital Costs</b>	<b>448,609</b>	
<b>TOTAL ANNUALIZED COSTS</b>	<b>968,120</b>	<b>Sum of Operating and Maintenance and Annualized Capital Costs</b>

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).

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 1,925,000 kWh/yr would result at 100 percent load. This energy penalty is sufficient to supply the electrical needs of about 160 residential customers over a year. To replace this lost energy, about  $1.93 \times 10^{10}$  Btu/yr or about 19 million ft<sup>3</sup>/yr of natural gas would be required.

#### 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 unreasonable for the following reasons:

1. Catalytic oxidation will not produce measurable reduction in the air quality impacts; and
2. The economic impacts are significant (i.e., an annualized cost of almost one million dollars, with a cost effectiveness of over \$2,700/ton of CO removed).
3. Actual CO emissions are expected to be one-half or less than those proposed. The proposed level is based on the lack of operating experience with the LM 6000 in industrial applications.

#### 4.3.3 OTHER REGULATED AND NONREGULATED POLLUTANT EMISSIONS

The PSD source applicability analysis shows that the PSD significant emission level is exceeded for PM, PM<sub>10</sub>, 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. Levels of trace metals in

distillate oil are limited by fuel oil specifications. Low-sulfur (0.1 percent or less) distillate oil represents BACT for this pollutant.

For the nonregulated pollutants, most of which are trace metals, none of the control technologies evaluated for other pollutants (i.e., SCR or oxidation catalyst) would reduce such emissions; thus, natural gas and low sulfur distillate oil represent BACT because of their inherent low metals content.



## 5.0 AIR QUALITY MONITORING DATA

### 5.1 PSD PRECONSTRUCTION

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

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

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

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

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

EPA's Ambient Monitoring Guidelines for 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 hypothetically would occur, based on the combined effect of existing sources and the proposed new source or modification).

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

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

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

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

## 5.2 PROJECT MONITORING APPLICABILITY

As determined by the source applicability analysis described in Section 3.4, an ambient monitoring analysis is required by PSD regulations for PM, NO<sub>2</sub>, CO, and As emissions. As may be exempt from monitoring requirements because no acceptable monitoring technique has been established for that pollutant. The maximum predicted impacts from the proposed turbines also are less than de minimis levels for PM, NO<sub>2</sub>, and CO. Therefore, preconstruction monitoring is not required for those pollutants for this project.

## 6.0 AIR QUALITY MODELING APPROACH

### 6.1 ANALYSIS APPROACH AND ASSUMPTIONS

#### 6.1.1 GENERAL MODELING APPROACH

The general modeling approach follows EPA and FDER modeling guidelines. The highest predicted concentrations are compared with both PSD significant impact levels and de minimis air quality levels. If a facility exceeds the significant impact level for a particulate pollutant, current policies stipulate that the highest annual average and HSH short-term (i.e., 24 hours or less) concentrations be compared with AAQS and PSD increments when 5 years of meteorological data are used. The HSH concentration is calculated for a receptor field by:

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

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

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

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

approach was used to ensure that valid HSH concentrations were obtained. More detailed descriptions of the emission inventory and receptor grids used in the screening and refined phases of the analysis are presented in the following sections.

#### 6.1.2 MODEL SELECTION

The selection of the appropriate air dispersion model was based on its ability to simulate impacts in areas surrounding the plant site. Within 50 km of the site, the terrain can be described as 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 that are used to calculate short- and long-term ground level concentrations. The main differences between the two codes are the input format of the meteorological data and the method of estimating the plume's horizontal dispersion.

The first model code, the ISC short-term (ISCST) model, is an extended version of the single-source (CRSTER) model (EPA, 1977). The ISCST model is designed to calculate hourly concentrations based on hourly meteorological parameters (i.e., wind direction, wind speed, atmospheric stability, ambient temperature, and mixing heights). The hourly concentrations are processed into non-overlapping, short-term, and annual

averaging periods. For example, a 24-hour average concentration is based on twenty-four 1-hour averages calculated from midnight to midnight of each day. For each short-term averaging period selected, the highest and second-highest average concentrations are calculated for each receptor. As an option, a table of the 50 highest concentrations over the entire field of receptors can be produced.

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

In this analysis, the ISCST model was used to calculate both short-term and annual average concentrations because these concentrations are readily obtainable from the model output. Major features of the ISCST model are presented in Table 6-1. Concentrations caused by stack and volume sources are calculated by the ISCST model using the steady-state Gaussian plume equation for a continuous source. The area source equation in the ISCST model is based on the equation for a continuous and finite crosswind line source. The ISC model has rural and urban options that affect the wind speed profile exponent law, dispersion rates, and mixing-height formulations used in calculating ground-level concentrations. The criteria used to determine when the rural or urban mode is appropriate are based on land use near the proposed plant's surroundings (Auer, 1978). If the land use is classified as heavy industrial, light-moderate industrial, commercial, or compact residential for more than 50 percent of the area 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
<ul style="list-style-type: none"><li>• Polar or Cartesian coordinate systems for receptor locations</li><li>• Rural or one of three urban options that affect wind speed profile exponent, dispersion rates, and mixing height calculations</li><li>• Plume rise as a result of momentum and buoyancy as a function of downwind distance for stack emissions (Briggs, 1969, 1971, 1972, and 1975)</li><li>• Procedures suggested by Huber and Snyder (1976); Huber (1977); Schulmann and Hanna (1986); and Schulmann and Scire (1980) for evaluating building wake effects</li><li>• Procedures suggested by Briggs (1974) for evaluating stack-tip downwash</li><li>• Separation of multiple-point sources</li><li>• Consideration of the effects of gravitational settling and dry deposition on ambient particulate concentrations</li><li>• Capability of simulating point, line, volume, and area sources</li><li>• Capability to calculate dry deposition</li><li>• Variation with height of wind speed (wind speed-profile exponent law)</li><li>• Concentration estimates for 1-hour to annual average</li><li>• Terrain-adjustment procedures for elevated terrain, including a terrain truncation algorithm</li><li>• Receptors located above local terrain (i.e., "flagpole" receptors)</li><li>• Consideration of time-dependent exponential decay of pollutants</li><li>• The method of Pasquill (1976) to account for buoyancy-induced dispersion</li><li>• A regulatory default option to set various model options and parameters to EPA recommended values (see text for regulatory options used)</li><li>• Procedure for calm-wind processing</li><li>• Wind speeds less than 1 m/s are set to 1 m/s.</li></ul>

Source: EPA, 1990.

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<sub>2</sub> concentrations in urban areas by using a decay half-life of 4 hours (i.e., reduce the SO<sub>2</sub> concentration emitted by 50 percent for every 4 hours of plume travel time).

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

## 6.2 METEOROLOGICAL DATA

Meteorological data used in the ISCST model to determine air quality impacts consisted of a concurrent 5-year period of hourly surface weather observations and twice-daily upper air soundings from the National Weather Service (NWS) stations at 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 53 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 HRSGs were presented in Section 2.0.

Modeling of the proposed turbines demonstrated that the facility's PM, NO<sub>x</sub>, and CO impacts are below the significant impact levels. Further modeling for this facility is not required.

### 6.4 RECEPTOR LOCATIONS

In the ISCST modeling, concentrations were predicted for the screening phase using a polar receptor grid. A description of the receptor locations for determining maximum predicted impacts is as follows:

The screening grid receptors consisted of 432 receptors located at distances of 47; 100; 300; 600; 900; 1,200; 1,600; 2,000; 2,500; 3,000; 4,000; and 5,000 m along 36 radials with each radial spaced at 10-degree

increments. The 47-m distance is representative of the minimum distance at which the ISCST model will predict a concentration for the modeled building height.

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

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

To ensure that a valid maximum concentration was calculated, concentrations were predicted using the refined grid for the entire year that produced the highest concentration from the screening receptor grid. If maximum concentrations for other years were within 10 percent of that for the highest year, they also were refined.

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

The maximum PSD increment consumption at the Chassahowitzka Wilderness Area, a PSD Class I area, was determined for the proposed facility alone. Receptors were located at 93 km and at radials 250° to 260° from the proposed facility at intervals of 2°. The highest predicted concentration over five years of meteorological data was compared with PSD Class I

allowable increments. The highest concentration was used because the proposed facility was below significant impact levels in Class II areas. The analysis was performed for both PM and NO<sub>x</sub>.

#### 6.5 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with buildings and structures planned at the plant, the stacks for the proposed turbines will be less than GEP. Therefore, the potential for building downwash to occur was considered in the modeling analysis.

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

1. Reduced plume rise as a result of initial plume dilution,
2. Enhanced plume spread as a linear function of the effective plume height, and
3. Specification of building dimensions as a function of wind direction.

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

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

$$M_w = 0.8886 W$$

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 6-2. 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 6-2. Building Dimensions Used in ISCST Modeling Analysis To Address Potential Building Wake Effects

Source	Associated Building	<u>Actual Building Dimensions (m)</u>			Projected	<u>Modeled Building Dimensions (m)</u>	
		Length	Width	Height	Width* (m)	Length, Width	Height
Proposed Turbines	Steam Generation Building	37.79	24.38	15.54	44.98	39.85	15.54

\*Diagonal of actual building dimensions.

## 7.0 AIR QUALITY MODELING RESULTS

### 7.1 PROPOSED UNITS ONLY

#### 7.1.1 SIGNIFICANT IMPACT ANALYSIS

A summary of the maximum concentrations as a result of the proposed turbines operating at maximum load conditions is presented in Table 7-1. The results are presented for a generic emission rate concentration of 10 g/s, and it is assumed that the stacks are collocated. Since the inlet air will be held constant by chillers, the operating load was assumed to be a 100 percent load under all operating conditions. Table 7-1 indicates the maximum screening concentrations for each year and averaging time with an emission rate of 10 g/s. Based on the results in Table 7-1, refined modeling was performed. The results of the refined modeling are presented in Table 7-2, including receptor location and the day and period of the maximum impacts. The maximum pollutant-specific concentrations for PM, NO<sub>2</sub>, and CO were determined from the maximum generic impacts and are presented in Table 7-3.

The maximum predicted NO<sub>2</sub> concentration as a result of the proposed turbines is 0.33 µg/m<sup>3</sup>. Since this concentration is below the significance level for NO<sub>2</sub> (1.0 µg/m<sup>3</sup>), no further modeling analysis is necessary for that pollutant. The maximum predicted 1-hour and 8-hour CO concentrations are 161.0 and 51.2 µg/m<sup>3</sup>, respectively. Because these concentrations are below the PSD significant levels of 2,000 and 500 µg/m<sup>3</sup>, additional modeling is not necessary for CO.

The maximum predicted annual and 24-hour average PM concentrations when firing oil only are 0.07 and 3.70 µg/m<sup>3</sup>, respectively. With the primary fuel, natural gas, the maximum impacts are 0.02 and 1.26 µg/m<sup>3</sup> for the annual and 24-hour averaging times, respectively. These maximum impacts are less than the PM significance impact levels. Therefore, additional modeling is not required for this pollutant.

Table 7-1. Maximum Predicted Impacts for the Lake County Cogeneration Facility Using a Generic Emission Rate of 10 g/s--Screening Analysis

Averaging Time	Year	Concentration ( $\mu\text{g}/\text{m}^3$ )	Receptor Location <sup>a</sup>		Day/Period
			Direction (degrees)	Distance (m)	
Annual	1982	0.26	240	2,000	/
	1983	0.23	240	2,000	/
	1984	0.28	240	2,000	/
	1985	0.25	250	2,000	/
	1986	0.21	240	2,000	/
1-Hour <sup>b</sup>	1982	84.57	360	100	169/ 8
	1983	62.64	80	100	83/16
	1984	63.45	340	100	272/ 4
	1985	53.72	90	100	137/17
	1986	42.72	100	100	27/14
3-Hour <sup>b</sup>	1982	31.66	100	100	14/ 6
	1983	39.30	80	100	83/ 6
	1984	47.59	340	100	272/ 2
	1985	36.54	90	100	137/ 6
	1986	27.08	100	100	27/ 5
8-Hour <sup>b</sup>	1982	11.39	360	100	31/ 2
	1983	15.14	80	300	114/ 2
	1984	18.04	340	100	272/ 1
	1985	23.07	90	100	43/ 1
	1986	10.87	60	100	58/ 2
24-Hour <sup>b</sup>	1982	6.14	100	100	14/ 1
	1983	6.12	120	100	70/ 1
	1984	6.56	40	100	88/ 1
	1985	12.81	90	100	43/ 1
	1986	5.51	100	100	27/ 1

<sup>a</sup>Relative to the location of the proposed units.<sup>b</sup>All short-term concentrations indicate highest predicted concentrations.

Table 7-2. Maximum Predicted Impacts for the Lake County Cogeneration Facility Using a Generic Emission Rate of 10 g/s--Refined Analysis

Averaging Time	Year	Concentration ( $\mu\text{g}/\text{m}^3$ )	Receptor Location <sup>a</sup>		Day/Period
			Direction (degrees)	Distance (m)	
Annual	1982	0.26	238	2,200	
	1984	0.28	240	2,100	
1-Hour <sup>b</sup>	1982	84.6	360	100	169/8
3-Hour <sup>b</sup>	1984	47.6	340	100	272/2
8-Hour <sup>b</sup>	1985	26.9	92	200	43/1
24-Hour <sup>b</sup>	1985	14.7	92	200	43/1

<sup>a</sup>Relative to the location of the proposed units.

<sup>b</sup>All short-term concentrations indicate highest predicted concentrations.



Table 7-3. Maximum Predicted Pollutant Impacts of the Lake County Cogeneration Facility Turbines Compared to PSD Significant Impact Levels

Pollutant	Averaging Period	Emission Rate (lb/hr)	Generic Impact ( $\mu\text{g}/\text{m}$ )	Predicted Impact ( $\mu\text{g}/\text{m}$ )	Significant Impact Level ( $\mu\text{g}/\text{m}$ )
Particulate Matter	Annual	20.0 <sup>a</sup>	0.28	0.07 (0.02)	1
	24-Hour	(6.8) <sup>b</sup>	14.7	3.70 (1.26)	5
Nitrogen Oxides	Annual	92.4 <sup>c</sup>	0.28	0.33	1
Carbon Monoxide	1-Hour	151.0 <sup>a</sup>	84.6	161.0 (149.9)	2,000
	8-Hour	(140.6) <sup>b</sup>	26.9	51.2 (47.7)	500

Note: Short-term maximum impacts are highest predicted concentrations for 1982-86.

<sup>a</sup> Emission rate for two turbines firing oil, which will only be used up to 240 hr/yr and only during natural gas curtailments.

<sup>b</sup> Emission rate for two turbines and duct burners firing natural gas, the primary fuel. Impacts for natural gas shown in parentheses.

<sup>c</sup> Emission rate based on 404.7 TPY.

#### 7.1.2 CLASS I ANALYSIS

The maximum predicted facility impacts at the Chassahowitzka Wilderness Area using a generic emission rate of 10 g/sec are presented in Table 7-4. The maximum annual and 24-hour generic impacts are 0.02 and 0.24  $\mu\text{g}/\text{m}^3$ . The pollutant-specific results are presented in Table 7-5. Based on a PM emission rate of 20 lb/hr (oil), the maximum PSD PM annual and 24-hour increment consumption is 0.005 and 0.06  $\mu\text{g}/\text{m}^3$ , respectively. These concentrations are considerably below the allowable increments of 1 and 5  $\mu\text{g}/\text{m}^3$ .

Based on a  $\text{NO}_x$  emission rate of 92.3 lb/hr (gas), the maximum  $\text{NO}_x$  PSD increment consumption is 0.02. This is well below the allowable increment of 2.5  $\mu\text{g}/\text{m}^3$ .

#### 7.2 TOXIC POLLUTANT ANALYSIS

The maximum impacts of regulated and nonregulated hazardous pollutants that will be emitted in significant amounts by the proposed facility (see Table 3-3) are presented in Table 7-6. Inorganic arsenic is the only pollutant to be addressed and is compared in the table to the Florida Department of Environmental Regulation (FDER) No Threat Levels (NTL). The maximum 8-hour, 24-hour, and annual impacts for arsenic are well below the NTL for each respective averaging time.

#### 7.3 ADDITIONAL IMPACT ANALYSIS

##### 7.3.1 IMPACTS UPON SOILS AND VEGETATION

Predicted impacts of all regulated pollutants are less than the significant impact levels (see Table 7-3). As a result, no impacts are expected to occur to soils or vegetation as a result of the proposed emissions of other regulated pollutants.

##### 7.3.2 IMPACTS DUE TO ADDITIONAL GROWTH

A limited number of additional personnel may be added to the current plant personnel. These additional personnel are expected to have an

insignificant effect on the residential, commercial, and industrial growth in Lake County.

#### 7.3.3 IMPACTS TO VISIBILITY

The plant is located approximately 93 km from the Chassahowitzka Wilderness Area, a PSD Class I area. Impacts to visibility were estimated using the VISCREEN computer model. Impacts were calculated for particulates and nitrogen oxides (as nitrogen dioxide). The results of the screening analysis are presented in Table 7-7. Based on the results, the proposed facility is not expected to significantly impair visibility in the Chassahowitzka Wilderness Area.

Table 7-4. Maximum Predicted PSD Class I Impacts for the Lake County Cogeneration Facility Using a Generic Emission Rate of 10 g/s

Averaging Time	Year	Concentration ( $\mu\text{g}/\text{m}^3$ )	Receptor Location <sup>a</sup>		Day/ Period
			Direction (degrees)	Distance (m)	
Annual					
	1982	0.01	250	93000	/
	1983	0.01	260	93000	/
	1984	0.01	250	93000	/
	1985	0.01	250	93000	/
	1986	0.02	254	93000	/
24-Hour <sup>b</sup>					
	1982	0.19	250	93000	114/ 1
	1983	0.15	258	93000	211/ 1
	1984	0.24	258	93000	132/ 1
	1985	0.20	256	93000	266/ 1
	1986	0.23	252	93000	297/ 1

<sup>a</sup>Relative to the location of the proposed units.

<sup>b</sup>All short-term concentrations indicate highest predicted concentrations.

Table 7-5. Maximum Predicted Pollutant Impacts of the Lake County Cogeneration Facility Turbines Compared to PSD Class I Allowable Increments

Pollutant	Averaging Period	Emission Rate (lb/hr)	Generic Impact ( $\mu\text{g}/\text{m}$ )	Predicted Impact ( $\mu\text{g}/\text{m}$ )	PSD Class I Increment ( $\mu\text{g}/\text{m}$ )
Particulate Matter (PM10)	Annual	20.0 <sup>a</sup>	0.02	0.005 (0.002)	4 <sup>d</sup>
	24-Hour	(6.8)	0.24	0.06 (0.02)	8 <sup>d</sup>
Nitrogen Oxides	Annual	92.4 <sup>b</sup>	0.02	0.02	2.5

Note: Short-term maximum impacts are highest predicted concentrations for 1982-86.

<sup>a</sup> Emission rate for two turbines firing oil, which will only be used up to 240 hr/yr and only during natural gas curtailments.

<sup>b</sup> Emission rate for two turbines and duct burners firing natural gas, the primary fuel. Impacts for natural gas shown in parentheses.

<sup>c</sup> Emission rate based on 404.7 TPY.

<sup>d</sup> Proposed.

Table 7-6. Predicted Maximum Impacts of Toxic Pollutants for the Lake County Cogeneration Facility

Pollutant	Averaging Period	Emission Rate (lb/hr)	Generic Impact ( $\mu\text{g}/\text{m}$ )	Predicted Impact ( $\mu\text{g}/\text{m}$ )	No Threat Levels ( $\mu\text{g}/\text{m}$ )
<u>Non-Regulated</u>					
Inorganic Arsenic	8-Hour	0.0033 <sup>a</sup>	26.9	0.0011	0.50
	24-Hour		14.7	0.0006	0.48
	Annual	$9.13 \times 10^{-5b}$	0.28	$3.2 \times 10^{-7}$	$2.3 \times 10^{-4}$

Note: Short-term generic impacts are highest predicted concentrations for 1982-86.

<sup>a</sup> Based on maximum emissions when firing oil, which will only be used for up to 240 hr/yr.

<sup>b</sup> Based on total TPY for two turbines.

Table 7-7. Visibility Analysis for the Lake County Cogeneration Facility on the PSD Class I Area

Visual Effects Screening Analysis for  
Source: LAKE COGENERATION FACILITY  
Class I Area: CHASSAHOWITZKA WILDERNESS AREA

*** Level-1 Screening ***			
Input Emissions for			
Particulates	27.00	TON/YR	
NOx (as NO2)	404.70	TON/YR	
Primary NO2	.00	TON/YR	
Soot	.00	TON/YR	
Primary SO4	.00	TON/YR	

\*\*\*\* Default Particle Characteristics Assumed

Transport Scenario Specifications:

Background Ozone:	.04 ppm
Background Visual Range:	25.00 km
Source-Observer Distance:	93.00 km
Min. Source-Class I Distance:	93.00 km
Max. Source-Class I Distance:	125.00 km
Plume-Source-Observer Angle:	11.25 degrees
Stability:	6
Wind Speed:	1.00 m/s

R E S U L T S

Asterisks (\*) indicate plume impacts that exceed screening criteria

Maximum Visual Impacts INSIDE Class I Area  
Screening Criteria ARE NOT Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	84.	93.0	84.	2.00	.023	.05	-.000
SKY	140.	84.	93.0	84.	2.00	.007	.05	-.000
TERRAIN	10.	84.	93.0	84.	2.00	.001	.05	.000
TERRAIN	140.	84.	93.0	84.	2.00	.000	.05	.000

Maximum Visual Impacts OUTSIDE Class I Area  
Screening Criteria ARE NOT Exceeded

Backgrnd	Theta	Azi	Distance	Alpha	Delta E		Contrast	
					Crit	Plume	Crit	Plume
SKY	10.	75.	90.0	94.	2.00	.024	.05	-.000
SKY	140.	75.	90.0	94.	2.00	.007	.05	-.000
TERRAIN	10.	65.	85.1	109.	2.00	.002	.05	.000
TERRAIN	140.	65.	85.1	109.	2.00	.000	.05	.000

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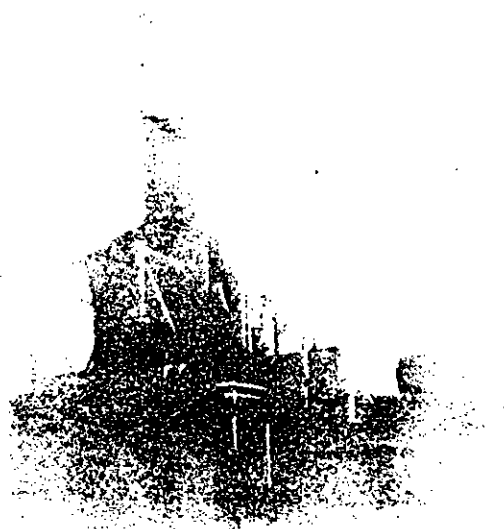
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**APPENDIX A**  
**MANUFACTURER'S ARTICLE**  
**EMISSION CALCULATIONS AND FACTORS**



***GE Marine &  
Industrial Engines***

**GE LM6000  
Development of the  
First 40%  
Thermal  
Efficiency  
Gas Turbine**



**G. Oganowski  
General Manager  
LM6000/LM1600 Projects  
GE Marine & Industrial Engine  
and Service Division**

# GE LM6000 Development of the First 40% Thermal Efficiency Gas Turbine

## ABSTRACT

General Electric has launched development of a new generation aeroderivative gas turbine, the LM6000. This 40MW-class machine, targeted for 1992 field service introduction, combines GE Aircraft Engines' latest engine technology together with a new method of aeroderivative load coupling to achieve two gas turbine firsts:

- The first simple cycle industrial gas turbine to achieve an iso base-rated thermal efficiency in excess of 40% (LHV).
- The first simple cycle, aeroderivative gas turbine to be competitive on a first cost basis with all other gas turbines in its size class.

This paper describes the LM6000 concept, basic engine, expected performance and development program for this revolutionary gas turbine.

## INTRODUCTION

Since their initial introduction in the 1960's, aeroderivative gas turbines have been at the industrial gas turbine forefront in terms of simple cycle efficiency. The close association of the aeroderivatives to their aircraft engine ancestors have allowed them to be close-coupled beneficiaries of the enormous amount of resources poured into aircraft engine research and technology development. The heavy weight industrial gas turbines have also benefitted greatly from this technology development but on a much delayed time scale and not to the full extent of the aeroderivatives. The result has been a consistent 4 to 5 percentage point thermal efficiency advantage for the aeroderivatives in industrial applications.

This efficiency advantage has come with a price tag, however. Although on a \$/hp basis, a high technology aircraft engine cost is comparable to that of a heavy weight industrial gas turbine, this is largely due to volume effects. A successful aircraft engine will have 5 to 10 times the annual production volume of a comparable successful industrial machine with the obvious effect on unit cost and development cost amortization. Where aeroderivative engines suffer on the cost front is in the area of modifying the machine for industrial use. Typically, this is done by developing unique hardware to adapt the high efficiency, high volume aircraft com-

ponents to drive a generator or other industrial load. Although the amount of unique hardware is generally small, the factor of 5 to 10 reduction in volume for these unique components can have a major impact on the total engine cost. The result is a hybrid machine that has the high efficiency of its ancestors but also a relatively high price tag due to the low volume unique components contained in the machine.

In 1988, GE's aeroderivative gas turbine arm, the Marine and Industrial Engines and Service Division (GE M&I), initiated studies to find a means of providing customers with the proven aeroderivative advantages of high efficiency, availability and maintainability but at a first cost significantly lower than previous machines. The result of that study and the development program internally launched at GE in mid-1989 is the LM6000. As described in subsequent sections of this paper, the LM6000 will not only provide aero technology at significantly lower cost but also will provide a quantum step in industrial gas turbine performance.

## CONCEPT

In trying to develop a more first-cost effective method of applying aircraft engines for industrial use, GE focussed on maximizing the commonality between the aircraft engine and the industrial derivative. This approach was viewed as having two advantages:

1. The higher volume aircraft common parts would bring the desired cost improvement, and
2. Maximizing use of aircraft common parts would improve performance relative to use of unique industrial parts which are designed with low volume as a major consideration with the tradeoff often being performance.

Figure 1 illustrates the approach used on the traditional aeroderivative machine like the LM5000. The twin spool LM5000 gas generator maintained a high degree of commonality with the parent aircraft engine, the CF6-50. The low pressure compressor (LPC), high pressure compressor (HPC), combustor and high pressure turbine (HPT) were nearly identical. The low pressure turbine (LPT) which drives the LPC and fan of the aircraft engine, however, was totally unique on the industrial machine. In effect, the aircraft engine LPT was split into two pieces – a single stage LPT for driving the gas generator LPC and a power turbine, aero-

dynamically coupled to the gas generator to drive the industrial load. The unique LPT and power turbine of the industrial machine, because of their relatively low volume, represent 40 to 50% of the cost of an LM5000 gas turbine. In addition, the more industrial-based design of the power turbine and its aerodynamic coupling resulted in the loss of some performance. The efficiency difference between the aircraft engine LPT and the combined aeroderivative LPT/power turbine is not insignificant.

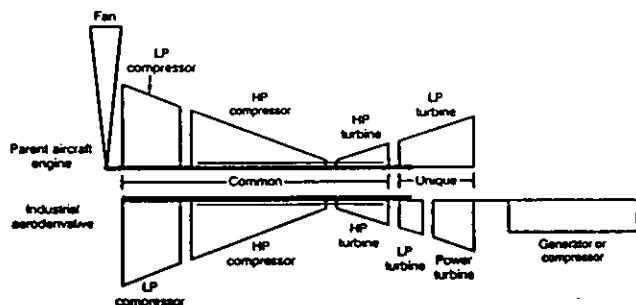


Figure 1  
Traditional adaptation of aircraft engine  
to industrial use.

The LM6000 gas turbine approach takes advantage of the fact that the low pressure rotor normal operating speed of the large turbofan aircraft engines, such as the GE CF6-80C2, is approximately 3600 rpm. The GE LM6000 concept provides for direct coupling of the gas turbine low pressure system to the load, as illustrated in Figure 2. For 60 cycle generator applications, the match is perfect. This concept allows the entire LPT of the aircraft engine to be utilized instead of a unique LPT and power turbine resulting in a nearly 10 to 1 reduction in the cost of these components of the engine. The result is a significant reduction in the cost of an LM6000 relative to its aeroderivative predecessors. In addition, use of the entire high tech aircraft engine LPT and direct coupling results in a precedent-setting improvement in engine performance – the first machine to exceed 40% (LVH) thermal efficiency

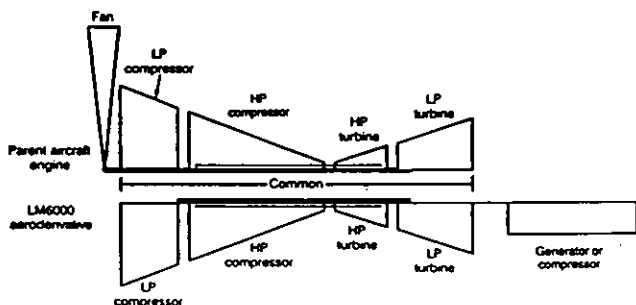


Figure 2  
LM6000 adaptation of aircraft engine  
to industrial application.

## LM6000 ENGINE

The LM6000 gas turbine is designed around GE's latest production aircraft engine, the CF6-80C2 (Figure 3). This engine, certified in 1985, is the industry's leading new power plant for large, widebody aircraft with more than 600 units in service and total firm orders in excess of 1600. The CF6-80C2 has set new standards for both performance and reliability during its initial 2 million hours of revenue service. This, combined with a production volume approaching 300 units per year made it a natural choice for use as the basis for the LM6000. Table 1 provides some CF6-80C2 statistics.

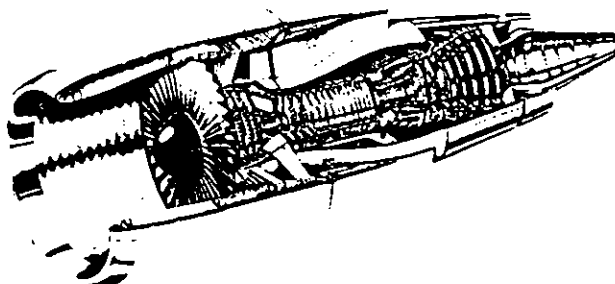


Figure 3  
GE CF6-80C2 Aircraft Engine.

Table 1  
CF6-80C2 Characteristics

Thrust	52,500 – 61,500 lbs.
Units in service (12/31/89)	557
Flight hours (12/31/89)	2.05 million
Applications	767; 747; A300; A310; A330; MD-11

The LM6000 gas turbine, shown in the Figure 4 and 5 cross-section and illustration utilizes the CF6-80C2 HPC, combustor, HPT and LPT almost totally intact. Only a minor seal change and modification of the LPT shaft to allow coupling to the load prevent these sections from being identical. The LPC is adapted from the LM5000 and its predecessor the CF6-50. This selection was made due to the excellent air flow match between this LPC and the cycle selected for the LM6000. The LPC rotor and stator airfoils are common to the LM5000 with the remaining hardware only slightly modified to adapt it to the CF6-80C2 mating components.

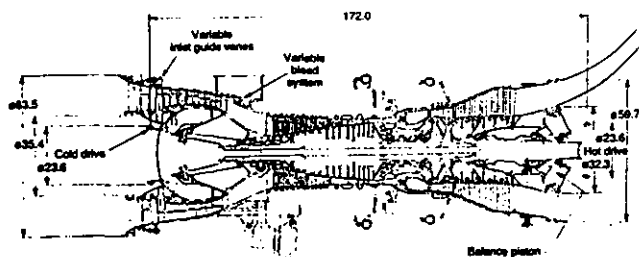


Figure 4  
LM6000 Cross-Section.

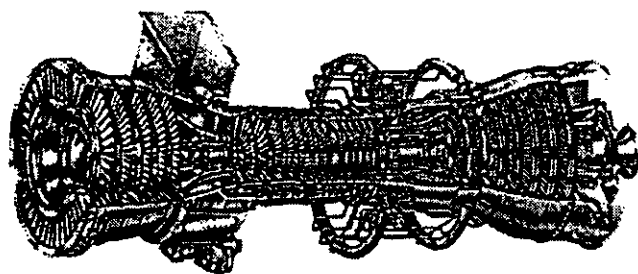


Figure 5  
GE LM6000 Aeroderivative Gas Turbine

A variable inlet guide vane system has been added to modulate airflow during startup, shutdown and part load operation when the low pressure system operates at a constant 3600 rpm while the high pressure system operates at reduced speed. A variable bleed system between the low pressure and high pressure systems will also function under these conditions to provide the proper match between LPC and HPC airflows.

The LM6000 rear frame area has been modified to provide a low pressure rotor thrust balance system needed to offset the 60,000 pounds of thrust lost with elimination of the fan from the engine.

Table 2 provides a description of the various engine sections.

As illustrated in Figure 4, the LM6000 will provide for both front and rear end drives. This feature will maximize the applicability of the machine by allowing two LM6000's to be coupled to a single generator for installations requiring higher output; by enabling LM6000's to be retrofit into older, existing installations with a minimum of modifications and by allowing package and facility designs to be optimized for the overall mission of the installation. All LM6000 gas turbines will be produced with front and rear drive capability.

The LM6000 will be initially offered with a variety of fuel and NOx suppressions alternatives as listed in Table 3.

Table 2  
LM6000 Engine Description

LPC	
Derived from:	LM5000/CF6-50
Normal operating speed	3600 rpm
Stages - Rotor	5
Stator	5 + VIGV
HPC	
Common to:	CF6-80C2
Stages - Rotor	14
Stator	14 (6 variable)
HPT	
Common to:	CF6-80C2
Stages - Rotor	2
Stator	2
LPT	
Common to:	CF6-80C2
Stages - Rotor	5
Stator	5
Overall length (fwd. coupling to rear coupling)	172.0 in
Total weight (estimated)	12,300 lbs

Table 3  
LM6000 Fuel/NOx System Alternatives

Fuel systems	NOx suppression (ref 15% O <sub>2</sub> )
Gas	Water - 25 ppm Steam - 25 ppm
Distillate	Water - 42 ppm
Dual fuel	Water - 42 ppm (liquid) Water - 25 ppm (gas)

## PERFORMANCE

On a simple cycle, dry, base-rated, ISO no-loss-basis, the LM6000 will produce 43.1MW at a thermal efficiency of 41.8% (LHV) at the gas turbine shaft. This precedent-setting performance is attributable to the LM6000 heritage in the latest proven aircraft engine technology and the method of application wherein it fully utilizes that aircraft engine technology.

This excellent performance extends to operation under more typical base load conditions requiring NOx suppression. Table 4 lists the LM6000 performance under base load, ISO conditions for various NOx level and method circumstances.

The base-rated conditions are established on a criteria of achieving a minimum of 25,000 hours between hot section maintenance actions and 50,000 hours

Table 4  
LM6000 Base Load Performance

NOx suppressant	Dry	Steam	Water
NOx level (ref 15%O <sub>2</sub> )	175 ppm	25 ppm	42 ppm
Inlet loss (in H <sub>2</sub> O)	4	4	4
Exhaust loss (in H <sub>2</sub> O)	4	10	4
Power (MW)	42.4	42.2	42.4
Heat rate (Btu/kW-hr) – LHV	8230	7980	8440
Thermal efficiency (%) – LHV	41.5%	42.8%	40.4%
Gas turbine exhaust temp (°F)	846	799	825
Gas turbine exhaust flow (lb/sec)	276	280	278
Pressure ratio			

Conditions:

- Base rating (25,000 hour hot section life; 50,000 hour overhaul)
- Sea level
- 59°F (15°C)
- Shaft performance
- 3600 rpm
- Natural gas
- 60% relative humidity

between overhauls. As with other aeroderivatives, the hot section maintenance activity at 25,000 hours will be accomplished on-site with only a 2-3 day outage.

The base load, off-design temperature performance of the LM6000 is illustrated in Figure 6. Two unusual characteristics are readily apparent:

1. The single curve is representative of three different operating modes (dry, steam to 25 ppm NOx and water to 42 ppm NOx).
2. Power falls off with ambient temperatures below ~60°F.

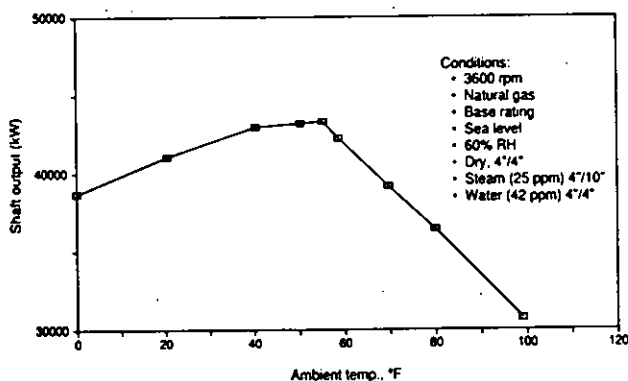


Figure 6  
LM6000 output vs. ambient temperature.

The reasons for these unusual characteristics lie in the conservative initial rating limitations established by GE to assure an experience-based, reliable introduction of the machine. Unlike most gas turbines which are

limited by turbine inlet temperature, the LM6000 introductory limits are based on mass flow-dependent parameters below ~60°F and by compressor exit temperature above 60°F. These limits have been set based on actual test and operating experience of the CF6-80C2. During development testing of the LM6000, the limiting characteristics will be examined at higher levels and, if justified by the results, the limits will be relaxed to allow the machine to operate up to its ultimate capability.

The base rating heat rate versus ambient performance is shown in Figure 7 and the part load performance is shown in Figure 8.

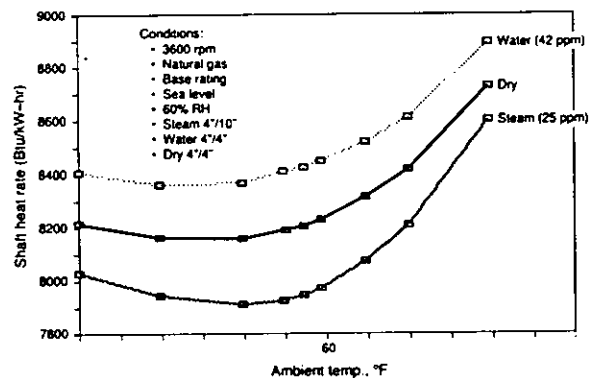


Figure 7  
LM6000 heat rate vs. ambient temperature

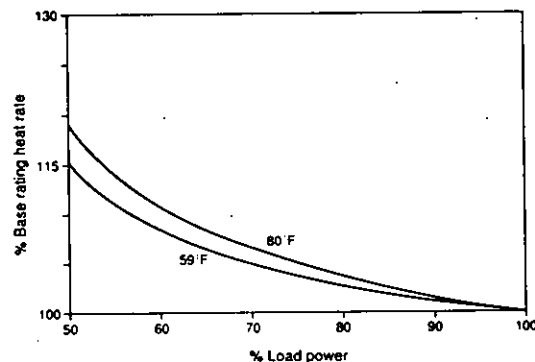


Figure 8  
LM6000 part load heat rate.

The above mentioned characteristics also affect the initial peak rating of the LM6000 as illustrated in Figure 9. As shown, below 60°F the base and peak ratings are the same. This again is due to the fact that GE has limited performance based on mass flow-dependent parameters. Above 60°F where compressor exit temperature is the limiting parameter, higher output is achievable. The rating in this region is based on a 6



year maintenance interval for a typical 1000 hour/year peaking application. Once again, when development testing increases the knowledge base, improved peak rating performance is expected.

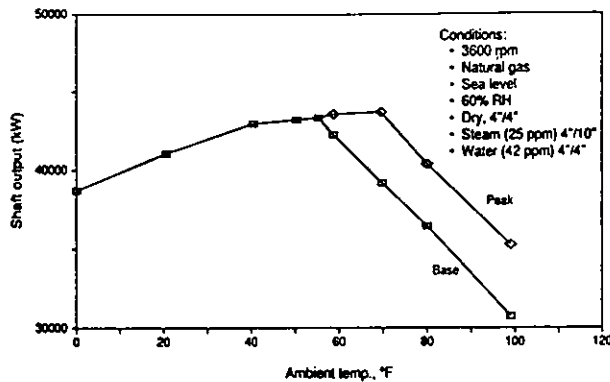


Figure 9  
LM6000 peak vs. base rating characteristics.

In combined cycle the LM6000 is also anticipated to provide industry-leading performance in its size class. Depending on the method used for NO<sub>x</sub> control, an LM6000 combined cycle system will produce from 49 to 53MW at the generator terminals with a thermal efficiency ranging from 49 to almost 52%.

The electrical generating performance discussed above is for 60 cycle application with this 3600 rpm driver. For 50 cycle applications, it is anticipated that a reduction gear will provide the most efficient, economic method of adapting the LM6000. Studies are being made to determine if modifications to the gas turbine are practical to achieve satisfactory 3000 rpm operation. It is expected, however, that the 3000 rpm engine uniqueness will result in a first cost and development cost impact that will exceed the 1-1.5 percentage point penalty associated with the gear.

## COST

GE's effort to develop an aeroderivative gas turbine with a cost significantly lower than previous aeroderivatives was quite successful. The minimizing of hardware in the LM6000 unique to the aircraft version of the engine has resulted in a machine expected to be competitive on a first cost basis with any machine in its size class.

## DEVELOPMENT PROGRAM

The high degree of utilization of existing aircraft engine hardware will enable GE to bring the LM6000 to reality on a schedule faster than traditional new gas

turbines. The program was internally launched at GE in mid-1989 and the first unit will go to test in Evendale, Ohio, in the third quarter of 1991. This testing, which will utilize a generator for load, will center on optimizing the variable geometry schedules of the gas turbine, qualifying the limited unique hardware and expanding the proven operating envelope of the machine to establish actual gas turbine capabilities.

The first LM6000 for field application will be shipped in late 1991 with full production anticipated to start in early 1992.

Additional program milestones are provided in Table 5.

Table 5

• Program launch (internal)	6/89
• Release to production	11/89
• Ratings established	4/90
• Detail design complete	3Q/90
• Public release	6/90
• First engine assembly complete	2Q/91
• First engine development test	3Q/91
• Ship first engine	4Q/91
• First production shipment	1Q/92
• First field engine operation	3Q/92

During the development program, GE has been working closely with its aeroderivative OEM's to provide installation and performance data to allow their development of system packages which will be both timely and, in character with the gas turbine, cost effective. With this close coordination, GE and its OEM's anticipate initial LM6000 field operation in mid- to late 1992 with significant early penetration of the market due to the superior economics of the LM6000 system.

Additional performance, installation and application information is now available from these OEM's.

## SUMMARY

In 1989, GE initiated development of a revolutionary aeroderivative industrial gas turbine in the 40 MW size range. The new machine, the LM6000, will achieve thermal efficiencies in excess of 40% and be provided at a cost comparable to less efficient heavy weight machines in the same size class. The LM6000 will direct drive the load from the aero-based low pressure gas turbine system to achieve the unprecedented cost and efficiency. Under development at GE's aircraft engine facility in Evendale, Ohio, the LM6000 will be tested in mid-1991 and achieve initial field operation in 1992.

## EMISSION CALCULATIONS AND FACTORS

Emission rates for all regulated and nonregulated pollutants were calculated using both manufacturer's data and EPA emission factors. The design information and emissions data are presented in Tables A-1 through A-5. These tables were generated using a computerized spreadsheet (i.e., Lotus 1-2-3). Tables A-1 through A-5 have been annotated to show the columns (i.e., A, B, C, and D) and rows (i.e., 1, 2, 3, ..... ) in the spreadsheet. Following these tables is a printout of all the calculations made in the spreadsheet, along with the basis for the calculation. The calculations, as well as text comments, are listed alphanumerically in ascending order. For example, in Table A-1, column D row 12 is listed as A:D12 on the calculation page, and the data input is 9232; as noted, these data were provided by General Electric (GE). A copy of the relevant EPA emission factors also is included in this appendix.

Table A-1. Design Information and Stack Parameters for  
Cogeneration Project

Data	Gas Turbine Natural Gas	Duct Burner Natural Gas	Gas Turbine Fuel Oil
A	B	C	D
General:			
Power (kW) <sup>a</sup>	42,044.0	NA	41,917.0
Heat Rate (Btu/kwh) <sup>a</sup>	9,112.0	NA	9,232.0
Heat Input (MMBtu/hr)	383.1	150.0	387.0
Fuel Oil (lb/hr)	18,533.4	7,256.5	21,031.4
(cf/hr)	403,268.3	157,894.7	
Fuel:			
Heat Content - (LHV)	20,671 Btu/lb	20,671 Btu/lb	18,400 Btu/lb
Sulfur	1 gr/100cf	1 gr/100cf	0.1
CT Exhaust:			
Volume Flow (acfm)	593,208		590,922
Volume Flow (scfm)	247,404		244,711
Mass Flow (lb/hr) <sup>b</sup>	1,079,779		1,081,322
Temperature (°F)	806		815
Moisture (% Vol.)	11.00		9.30
Oxygen (% Vol.)	13.36		13.46
Molecular Weight	28.03		28.38
Water Injected (lb/hr)	19,061		21,793
HRSG Stack:			
Volume Flow (acfm)	324,249		320,720
Temperature (°F)	232		232
Diameter (ft)	11.0		11.0
Velocity (ft/sec)	56.9		56.2

Source: General Electric and Stewart and Stevenson, 1991.

Note: All data shown on this table and subsequent tables are for each  
combustion turbine and duct burner.<sup>a</sup> Represents ISO conditions, which produces maximum potential emissions; actual  
operating power and heat rate will produce lower heat input.<sup>b</sup> A 5% margin added to maximize emissions since machine is new and the operating  
history in industrial applications has not yet been developed.

Table A-2. Maximum Criteria Pollutant Emissions for  
Cogeneration Project

Pollutant	Gas Turbine Natural Gas	Duct Burner Natural Gas	Gas Turbine Fuel Oil
A	B	C	D
Particulate:			
Basis	Manufacturer	0.006 lb/MMBtu	Manufacturer
lb/hr	2.50	0.90	10.0
TPY	10.95	1.58	1.2
Sulfur Dioxide:			
Basis	1 gr/100 cf	1 gr/100 cf	0.1% Sulfur
lb/hr	1.15	0.45	39.96
TPY	5.05	0.79	4.8
Nitrogen Oxides:			
Basis	25 ppm <sup>a</sup>	0.1 lb/MMBtu	42 ppm <sup>a</sup>
lb/hr	39.4	15.0	68.5
TPY	172.37	26.3	8.2
ppm	25.0	NA	42.0
Carbon Monoxide:			
Basis	42 ppm <sup>b</sup>	0.2 lb/MMBtu	78 ppm <sup>b</sup>
lb/hr	40.3	30.0	75.5
TPY	176.58	52.5	9.1
ppm	42.0	NA	78.0
VOCs:			
Basis	4 ppm <sup>b</sup>	0.03 lb/MMBtu	10 ppm <sup>b</sup>
lb/hr	1.65	4.50	4.15
TPY	7.2	7.9	0.5
ppm	4.0	NA	10.0
Lead:			
Basis			EPA(1988)
lb/hr	NA	NA	3.44E-03
TPY	NA	NA	4.13E-04

<sup>a</sup> Corrected to 15% O<sub>2</sub> dry conditions.<sup>b</sup> Corrected to dry conditions.

Note: Annual emission for CT when firing natural gas based on 8,760 hr/yr  
and 240 hr/yr for fuel oil firing. Annual emissions for duct burners  
on 3,500 hr/yr.

Table A-3. Maximum Other Regulated Pollutant Emissions for  
Cogeneration Project

Pollutant	Gas Turbine Natural Gas	Duct Burner Natural Gas	Gas Turbine No.2 Oil
A	B	C	D
As (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	0.0016253065248 1.95E-04
Be (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	0.00096744436 1.16E-04
Hg (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	1.16E-03 1.39E-04
F (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	0.01257677668 1.51E-03
H2SO4 (lb/hr) (TPY)	8.81E-03 3.86E-02	3.45E-03 6.04E-03	3.22E+00 3.86E-01

Sources: EPA, 1988; EPA, 1980

Table A-4. Maximum Nonregulated Pollutant Emissions for  
Cogeneration Project

Pollutant	Gas Turbine Natural Gas	Duct Burner Natural Gas	Gas Turbine No.2 Oil
A	B	C	D
Manganese (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	2.49E-03 2.99E-04
Nickel (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	6.58E-02 7.89E-03
Cadmium (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	4.06E-03 4.88E-04
Chromium (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	1.84E-02 2.21E-03
Copper (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	1.08E-01 1.30E-02
Vanadium (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	2.70E-02 3.24E-03
Selenium (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	9.08E-03 1.09E-03
POM (lb/hr) (TPY)	4.27E-04 1.87E-03	1.67E-04 2.93E-04	1.08E-04 1.30E-05
Formaldehyde (lb/hr) (TPY)	3.38E-02 1.48E-01	6.08E-02 1.06E-01	1.57E-01 1.88E-02

Table A-5. Maximum Emissions for Additional Nonregulated Pollutant  
for Cogeneration Project

Pollutant A	Gas Turbine Natural Gas B	Duct Burner Natural Gas C	Gas Turbine No.2 Oil D
Antimony (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	8.45E-03 1.01E-03
Barium (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	7.55E-03 9.07E-04
Cobalt (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	3.51E-03 4.21E-04
Zinc (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	2.64E-01 3.17E-02
Chlorine <sup>a</sup> (lb/hr) (TPY)	NEG. NEG.	NEG. NEG.	1.05E-02 1.26E-03

Source: EPA, 1979

<sup>a</sup>Assumes 0.5 ppm in fuel oil.

A:A1: [W24] 'Table A-1. Design Information and Stack Parameters for

A:E1: [W6] 1

A:A2: [W24] ' Cogeneration Project

A:E2: [W6] (E1+1)

A:A3: [W24] \

A:B3: [W18] \

A:C3: [W18] \

A:D3: [W18] \

A:E3: [W6] (E2+1)

A:E4: [W6] (E3+1)

A:A5: [W24] ^Data

A:B5: [W18] "Gas Turbine

A:C5: [W18] "Duct Burner

A:D5: [W18] "Gas Turbine

A:E5: [W6] (E4+1)

A:B6: [W18] "Natural Gas

A:C6: [W18] "Natural Gas

A:D6: [W18] "Fuel Oil

A:E6: [W6] (E5+1)

A:A7: [W24] ^A

A:B7: [W18] "B

A:C7: [W18] "C

A:D7: [W18] "D

A:E7: [W6] (E6+1)

A:A8: [W24] \

A:B8: [W18] \

A:C8: [W18] \

A:D8: [W18] \

A:E8: [W6] (E7+1)

A:E9: [W6] (E8+1)

A:A10: [W24] ^General:

A:E10: [W6] (E9+1)

A:A11: [W24] 'Power (kW)

A:B11: (,1) [W18] 42044 . . . . . From GE

A:C11: (,1) [W18] "NA

A:D11: (,1) [W18] 41917 . . . . . From GE

A:E11: [W6] (E10+1)

A:A12: [W24] 'Heat Rate (Btu/kwh)

A:B12: (,1) [W18] 9112 . . . . . From GE

A:C12: (,1) [W18] "NA

A:D12: (,1) [W18] 9232 . . . . . From GE

A:E12: [W6] (E11+1)

A:A13: [W24] 'Heat Input (mmBtu/hr)

A:B13: (,1) [W18] (B11\*B12/1000000) . . . . . Power \* Heat Rate

A:C13: (,1) [W18] 150 . . . . . Maximum Proposed

A:D13: (,1) [W18] (D11\*D12/1000000) . . . . . Power \* Heat Rate

A:E13: [W6] (E12+1)

A:A14: [W24] 'Fuel Oil (lb/hr)

A:B14: (,1) [W18] (B13/0.020671) . . . . . Heat Input ÷ Heat Content



A:C14: (,1) [W18] (C13/0.020671)  
A:D14: (,1) [W18] (D13/0.0184)  
A:E14: [W6] (E13+1)  
A:A15: [W24] ' (cf/hr)  
A:B15: (,1) [W18] (B13/950\*10^6) . . . . . Heat Input ÷ Heat Content  
A:C15: (,1) [W18] (C13/950\*10^6)  
A:E15: [W6] (E14+1)  
A:E16: [W6] (E15+1)  
A:A17: [W24] ^Fuel:  
A:E17: [W6] (E16+1)  
A:A18: [W24] 'Heat Content - (LHV)  
A:B18: (,1) [W18] "20,671 Btu/lb . . . . . Fuel Specification  
A:C18: (,1) [W18] "20,671 Btu/lb  
A:D18: (,1) [W18] "18,400 Btu/lb  
A:E18: [W6] (E17+1)  
A:A19: [W24] 'Sulfur  
A:B19: (,1) [W18] "1 gr/100cf . . . . . Maximum Sulfur Content in Natural Gas  
A:C19: (,1) [W18] "1 gr/100cf  
A:D19: (,1) [W18] 0.1 . . . . . Maximum Sulfur Content in Fuel Oil  
A:E19: [W6] (E18+1)  
A:E20: [W6] (E19+1)  
A:A21: [W24] ^CT Exhaust:  
A:E21: [W6] (E20+1)  
A:A22: [W24] 'Volume Flow (acfm)  
A:B22: (,0) [W18] (B24\*1545\*(460+B25)/(B28\*2116.8\*60)) . . . . . See Note A  
A:D22: (,0) [W18] (D24\*1545\*(460+D25)/(D28\*2116.8\*60))  
A:E22: [W6] (E21+1)  
A:A23: [W24] 'Volume Flow (scfm)  
A:B23: (,0) [W18] (B24\*1545\*(460+68)/(B28\*2116.8\*60)) . . . . . See Note A  
A:D23: (,0) [W18] (D24\*1545\*(460+68)/(D28\*2116.8\*60))  
A:E23: [W6] (E22+1)  
A:A24: [W24] 'Mass Flow (lb/hr)  
A:B24: (,0) [W18] 1028361\*1.05 . . . . . From GE w/ 5% Margin  
A:D24: (,0) [W18] 1029830\*1.05  
A:E24: [W6] (E23+1)  
A:A25: [W24] 'Temperature (oF)  
A:B25: (,0) [W18] 806 . . . . . From GE  
A:D25: (,0) [W18] 815  
A:E25: [W6] (E24+1)  
A:A26: [W24] 'Moisture (% Vol.)  
A:B26: (F2) [W18] 10.9989 . . . . . From GE  
A:D26: (F2) [W18] 11.5039  
A:E26: [W6] (E25+1)  
A:A27: [W24] 'Oxygen (% Vol.)  
A:B27: (F2) [W18] 13.3597 . . . . . From GE  
A:D27: (F2) [W18] 13.3161  
A:E27: [W6] (E26+1)  
A:A28: [W24] 'Molecular Weight  
A:B28: (F2) [W18] 28.0323 . . . . . Calculated from GE

A:D28: (F2) [W18] 27.9796  
A:E28: [W6] (E27+1)  
A:A29: [W24] 'Water Injected (lb/hr)  
A:B29: (,0) [W18] 19061 . . . . . From GE  
A:D29: (,0) [W18] 21793  
A:E29: [W6] (E28+1)  
A:E30: [W6] (E29+1)  
A:A31: [W24] ^HRSG Stack:  
A:E31: [W6] (E30+1)  
A:A32: [W24] 'Volume Flow (acfm)  
A:B32: (,0) [W18] (B22\*(B33+460)/(B25+460)) . . . . . Adjustment for Temperature  
A:D32: (,0) [W18] (D22\*(D33+460)/(D25+460))  
A:E32: [W6] (E31+1)  
A:A33: [W24] 'Temperature (oF)  
A:B33: (,0) [W18] 232 . . . . . From Design Engineer  
A:D33: (,0) [W18] 232  
A:E33: [W6] (E32+1)  
A:A34: [W24] 'Diameter (ft)  
A:B34: (,1) [W18] 11  
A:D34: (,1) [W18] 11  
A:E34: [W6] (E33+1)  
A:A35: [W24] 'Velocity (ft/sec)  
A:B35: (,1) [W18] (B32/60/(B34^2\*3.14159/4)) . . . . . Volume ÷ Flow  
A:D35: (,1) [W18] (D32/60/(D34^2\*3.14159/4))  
A:E35: [W6] (E34+1)  
A:E36: [W6] (E35+1)  
A:A37: [W24] \\_  
A:B37: [W18] \\_  
A:C37: [W18] \\_  
A:D37: [W18] \\_  
A:E37: [W6] (E36+1)  
A:E38: [W6] (E37+1)  
A:A39: [W24] 'Source: General Electric and Stewart and Stevenson, 1991.  
A:E39: [W6] (E38+1)  
A:A40: [W24] 'Note: All data shown on this table and subsequent tables are for each  
A:E40: [W6] (E39+1)  
A:A41: [W24] ' combustion turbine and duct burner.  
A:E41: [W6] (E40+1)  
A:A47: [W24] 'Table A-2. Maximum Criteria Pollutant Emissions for  
A:E47: [W6] 47  
A:A48: [W24] ' Cogeneration Project  
A:E48: [W6] (E47+1)  
A:A49: [W24] \\_  
A:B49: [W18] \\_  
A:C49: [W18] \\_  
A:D49: [W18] \\_  
A:E49: [W6] (E48+1)  
A:E50: [W6] (E49+1)  
A:A51: [W24] ^Pollutant

A:B51: [W18] "Gas Turbine  
 A:C51: [W18] "Duct Burner  
 A:D51: [W18] "Gas Turbine  
 A:E51: [W6] (E50+1)  
 A:B52: [W18] "Natural Gas  
 A:C52: [W18] "Natural Gas  
 A:D52: [W18] "Fuel Oil  
 A:E52: [W6] (E51+1)  
 A:A53: [W24] ^A  
 A:B53: [W18] "B  
 A:C53: [W18] "C  
 A:D53: [W18] "D  
 A:E53: [W6] (E52+1)  
 A:A54: [W24] \\_  
 A:B54: [W18] \\_  
 A:C54: [W18] \\_  
 A:D54: [W18] \\_  
 A:E54: [W6] (E53+1)  
 A:E55: [W6] (E54+1)  
 A:A56: [W24] 'Particulate:  
 A:E56: [W6] (E55+1)  
 A:A57: [W24] ' Basis  
 A:B57: (,1) [W18] "Manufacturer  
 A:C57: (,1) [W18] "0.006 lb/mmBtu  
 A:D57: (,1) [W18] "Manufacturer  
 A:E57: [W6] (E56+1)  
 A:A58: [W24] ' lb/hr  
 A:B58: (F2) [W18] 2.5 . . . . . From GE  
 A:C58: (F2) [W18] (C13\*0.006) . . . . . Emission Factor Based on GE  
 A:D58: (F1) [W18] 10 . . . . . From GE  
 A:E58: [W6] (E57+1)  
 A:A59: [W24] ' TPY  
 A:B59: (F2) [W18] (B58\*8760/2000) . . . . . Emissions \* 8,760 hours/year + 2,000 lb/ton  
 A:C59: (F2) [W18] (C58\*3500/2000) . . . . . Emissions \* 3,500 hours/year + 2,000 lb/ton  
 A:D59: (,1) [W18] (D58\*240/2000) . . . . . Emissions \* 240 hours/year + 2,000 lb/ton  
 A:E59: [W6] (E58+1)  
 A:E60: [W6] (E59+1)  
 A:A61: [W24] 'Sulfur Dioxide:  
 A:E61: [W6] (E60+1)  
 A:A62: [W24] ' Basis  
 A:B62: (,1) [W18] "1 gr/100 cf  
 A:C62: (,1) [W18] "1 gr/100 cf  
 A:D62: (,1) [W18] "0.1 % Sulfur  
 A:E62: [W6] (E61+1)  
 A:A63: [W24] ' lb/hr  
 A:B63: (F2) [W18] (B15\*1/7000\*2/100) . . . . . Fuel Used (CF/HR) \* Sulfur Content \* 2 lb SO<sub>2</sub>/lb S \* 1/100 CF  
 A:C63: (F2) [W18] (C15\*1/7000\*2/100)  
 A:D63: (F2) [W18] (D14\*0.001\*2\*0.95) . . . . . Fuel Used (lb/hr) \* Sulfur Content \* 2 lb SO<sub>2</sub>/lb S \* 95% Emitted  
 A:E63: [W6] (E62+1)

A:A64: [W24] ' TPY  
 A:B64: (F2) [W18] (B63\*8760/2000)  
 A:C64: (F2) [W18] (C63\*3500/2000)  
 A:D64: (,1) [W18] (D63\*240/2000)  
 A:E64: [W6] (E63+1)  
 A:E65: [W6] (E64+1)  
 A:A66: [W24] 'Nitrogen Oxides:  
 A:E66: [W6] (E65+1)  
 A:A67: [W24] ' Basis  
 A:B67: (,1) [W18] "25 ppm\*  
 A:C67: (,1) [W18] "0.1 lb/mmBtu  
 A:D67: (,1) [W18] "42 ppm\*  
 A:E67: [W6] (E66+1)  
 A:A68: [W24] ' lb/hr  
 A:B68: (,1) [W18] (B70/5.9\*(20.9\*(1-B26/100)-B27)\*B22\*2116.8\*46\*60/(1545\*(460+B25)\*1000000)) . . . . . See Note B  
 A:C68: (,1) [W18] (C13\*0.1) . . . . . Heat Input \* Emission Factor  
 A:D68: (,1) [W18] (D70/5.9\*(20.9\*(1-D26/100)-D27)\*D22\*2116.8\*46\*60/(1545\*(460+D25)\*1000000)) . . . . . See Note B  
 A:E68: [W6] (E67+1)  
 A:A69: [W24] ' TPY  
 A:B69: (F2) [W18] (B68\*8760/2000)  
 A:C69: (,1) [W18] (C68\*3500/2000)  
 A:D69: (,1) [W18] (D68\*240/2000)  
 A:E69: [W6] (E68+1)  
 A:A70: [W24] ' ppm  
 A:B70: (,1) [W18] 25 . . . . . From GE  
 A:C70: (,1) [W18] "NA  
 A:D70: (,1) [W18] 42 . . . . . From GE  
 A:E70: [W6] (E69+1)  
 A:E71: [W6] (E70+1)  
 A:A72: [W24] 'Carbon Monoxide:  
 A:E72: [W6] (E71+1)  
 A:A73: [W24] ' Basis  
 A:B73: (,1) [W18] "42 ppm+ . . . . . From GE  
 A:C73: (,1) [W18] "0.2 lb/mmBtu . . . . . From GE  
 A:D73: (,1) [W18] "78 ppm+ . . . . . From GE  
 A:E73: [W6] (E72+1)  
 A:A74: [W24] ' lb/hr  
 A:B74: (,1) [W18] (B76\*(1-B26/100)\*B22\*2116.8\*28\*60/(1545\*(460+B25)\*1000000)) . . . . . See Note C  
 A:C74: (,1) [W18] (C13\*0.2) . . . . . Heat Input \* Emission Factor  
 A:D74: (,1) [W18] (D76\*(1-D26/100)\*D22\*2116.8\*28\*60/(1545\*(460+D25)\*1000000)) . . . . . See Note C  
 A:E74: [W6] (E73+1)  
 A:A75: [W24] ' TPY  
 A:B75: (F2) [W18] (B74\*8760/2000)  
 A:C75: (,1) [W18] (C74\*3500/2000)  
 A:D75: (,1) [W18] (D74\*240/2000)  
 A:E75: [W6] (E74+1)  
 A:A76: [W24] ' ppm  
 A:B76: (,1) [W18] 42  
 A:C76: (,1) [W18] "NA  
 A:D76: (,1) [W18] 78

A:E76: [W6] (E75+1)  
 A:E77: [W6] (E76+1)  
 A:A78: [W24] 'VOC's:  
 A:E78: [W6] (E77+1)  
 A:A79: [W24] ' Basis  
 A:B79: (,1) [W18] "4 ppm+  
 A:C79: (,1) [W18] "0.03 lb/mmBtu  
 A:D79: (,1) [W18] "10 ppm+  
 A:E79: [W6] (E78+1)  
 A:A80: [W24] ' lb/hr  
 A:B80: (F2) [W18]  $(B82*(1-B26/100)*B22*2116.8*12*60/(1545*(460+B25)*1000000))$  . . . . . See Note C  
 A:C80: (F2) [W18]  $(C13*0.03)$   
 A:D80: (F2) [W18]  $(D82*(1-D26/100)*D22*2116.8*12*60/(1545*(460+D25)*1000000))$   
 A:E80: [W6] (E79+1)  
 A:A81: [W24] ' TPY  
 A:B81: (,1) [W18]  $(B80*8760/2000)$   
 A:C81: (,1) [W18]  $(C80*3500/2000)$   
 A:D81: (,1) [W18]  $(D80*240/2000)$   
 A:E81: [W6] (E80+1)  
 A:A82: [W24] ' ppm  
 A:B82: (,1) [W18] 4  
 A:C82: (,1) [W18] "NA  
 A:D82: (,1) [W18] 10  
 A:E82: [W6] (E81+1)  
 A:E83: [W6] (E82+1)  
 A:A84: [W24] 'Lead:  
 A:E84: [W6] (E83+1)  
 A:A85: [W24] ' Basis  
 A:D85: [W18] "EPA(1988)  
 A:E85: [W6] (E84+1)  
 A:A86: [W24] ' lb/hr  
 A:B86: (S2) [W18] "NA  
 A:C86: (S2) [W18] "NA  
 A:D86: (S2) [W18]  $(D13*8.9/1000000)$  . . . . . From EPA 1988; Page 4-156; Heat Input \* Emission Factor  
 A:E86: [W6] (E85+1)  
 A:A87: [W24] ' TPY  
 A:B87: (S2) [W18] "NA  
 A:C87: (S2) [W18] "NA  
 A:D87: (S2) [W18]  $(D86*240/2000)$   
 A:E87: [W6] (E86+1)  
 A:A88: [W24] \\_  
 A:B88: [W18] \\_  
 A:C88: [W18] \\_  
 A:D88: [W18] \\_  
 A:E88: [W6] (E87+1)  
 A:E89: [W6] (E88+1)  
 A:A90: [W24] '\* corrected to 15% O2 dry conditions  
 A:E90: [W6] (E89+1)  
 A:A91: [W24] '+ corrected to dry conditions  
 A:E91: [W6] (E90+1)

A:A92: [W24] 'Note: Annual emission for CT when firing natural gas based on 8,760 hrs/yr  
A:E92: [W6] (E91+1)  
A:A93: [W24] ' and 240 hrs/yr for fuel oil firing. Annual emissions for duct burners  
A:E93: [W6] (E92+1)  
A:A94: [W24] ' on 3,500 hrs/yr.  
A:E94: [W6] (E93+1)  
A:A96: [W24] 'Table A-3. Maximum Other Regulated Pollutant Emissions for  
A:E96: [W6] 96  
A:A97: [W24] ' Cogeneration Project  
A:E97: [W6] (E96+1)  
A:A98: [W24] \\_  
A:B98: [W18] \\_  
A:C98: [W18] \\_  
A:D98: [W18] \\_  
A:E98: [W6] (E97+1)  
A:E99: [W6] (E98+1)  
A:A100: [W24] ^Pollutant  
A:B100: [W18] "Gas Turbine  
A:C100: [W18] "Duct Burner  
A:D100: [W18] "Gas Turbine  
A:E100: [W6] (E99+1)  
A:B101: [W18] "Natural Gas  
A:C101: [W18] "Natural Gas  
A:D101: [W18] "No.2 Oil  
A:E101: [W6] (E100+1)  
A:A102: [W24] ^A  
A:B102: [W18] "B  
A:C102: [W18] "C  
A:D102: [W18] "D  
A:E102: [W6] (E101+1)  
A:A103: [W24] \\_  
A:B103: [W18] \\_  
A:C103: [W18] \\_  
A:D103: [W18] \\_  
A:E103: [W6] (E102+1)  
A:E104: [W6] (E103+1)  
A:A105: [W24] ' As (lb/hr)  
A:B105: [W18] "NEG.  
A:C105: [W18] "NEG.  
A:D105: [W18] (D13\*4.2/1000000) . . . . . From EPA 1988, See Page 4-158  
A:E105: [W6] (E104+1)  
A:A106: [W24] ' (TPY)  
A:B106: [W18] "NEG.  
A:C106: [W18] "NEG.  
A:D106: (S2) [W18] (D105\*240/2000)  
A:E106: [W6] (E105+1)  
A:E107: [W6] (E106+1)  
A:A108: [W24] ' Be (lb/hr)  
A:B108: [W18] "NEG.  
A:C108: [W18] "NEG.

A:D108: [W18] (D13\*2.5/1000000) . . . . . From EPA 1988, See Page 4-159  
A:E108: [W6] (E107+1)  
A:A109: [W24] ' (TPY)  
A:B109: [W18] "NEG.  
A:C109: [W18] "NEG.  
A:D109: (S2) [W18] (D108\*240/2000)  
A:E109: [W6] (E108+1)  
A:E110: [W6] (E109+1)  
A:A111: [W24] ' Hg (lb/hr)  
A:B111: [W18] "NEG.  
A:C111: [W18] "NEG.  
A:D111: (S2) [W18] (D13\*3/1000000) . . . . . From EPA 1988, See Page 4-157  
A:E111: [W6] (E110+1)  
A:A112: [W24] ' (TPY)  
A:B112: [W18] "NEG.  
A:C112: [W18] "NEG.  
A:D112: (S2) [W18] (D111\*240/2000)  
A:E112: [W6] (E111+1)  
A:E113: [W6] (E112+1)  
A:A114: [W24] ' F (lb/hr)  
A:B114: [W18] "NEG.  
A:C114: [W18] "NEG.  
A:D114: [W18] (D13\*32.5/1000000) . . . . . From EPA 1981, 2.324 pq/J \* 14 pq/J = 32.5 lb/10<sup>6</sup> BTU  
A:E114: [W6] (E113+1)  
A:A115: [W24] ' (TPY)  
A:B115: [W18] "NEG.  
A:C115: [W18] "NEG.  
A:D115: (S2) [W18] (D114\*240/2000)  
A:E115: [W6] (E114+1)  
A:E116: [W6] (E115+1)  
A:A117: [W24] ' H2SO4 (lb/hr)  
A:B117: (S2) [W18] (B63\*0.005\*3.06/2) . . . . . SO<sub>2</sub> Emission \* 0.005 (%H<sub>2</sub>SO<sub>4</sub> Formed) \* MW<sub>H2SO4</sub>/MW<sub>SO2</sub>  
A:C117: (S2) [W18] (C63\*0.005\*3.06/2) . . . . . SO<sub>2</sub> emissions \* %H<sub>2</sub>SO<sub>4</sub> formed (5%) \* MW<sub>H2SO4</sub>/MW<sub>SO2</sub> \* correction to total SO<sub>2</sub>  
A:D117: (S2) [W18] (D63\*0.05\*3.06/2/0.95)  
A:E117: [W6] (E116+1)  
A:A118: [W24] ' (TPY)  
A:B118: (S2) [W18] (B117\*8760/2000)  
A:C118: (S2) [W18] (C117\*3500/2000)  
A:D118: (S2) [W18] (D117\*240/2000)  
A:E118: [W6] (E117+1)  
A:E119: [W6] (E118+1)  
A:A120: [W24] \\_  
A:B120: [W18] \\_  
A:C120: [W18] \\_  
A:D120: [W18] \\_  
A:E120: [W6] (E119+1)  
A:E121: [W6] (E120+1)  
A:A122: [W24] 'Sources: EPA, 1988; EPA, 1980  
A:E122: [W6] (E121+1)  
A:A125: [W24] 'Table A-4. Maximum Non-Regulated Pollutant Emissions for

A:E125: [W6] 125  
A:A126: [W24] ' Cogeneration Project  
A:E126: [W6] (E125+1)  
A:A127: [W24] \\_  
A:B127: [W18] \\_  
A:C127: [W18] \\_  
A:D127: [W18] \\_  
A:E127: [W6] (E126+1)  
A:E128: [W6] (E127+1)  
A:A129: [W24] ^Pollutant  
A:B129: [W18] "Gas Turbine  
A:C129: [W18] "Duct Burner  
A:D129: [W18] "Gas Turbine  
A:E129: [W6] (E128+1)  
A:B130: [W18] "Natural Gas  
A:C130: [W18] "Natural Gas  
A:D130: [W18] "No.2 Oil  
A:E130: [W6] (E129+1)  
A:A131: [W24] ^A  
A:B131: [W18] "B  
A:C131: [W18] "C  
A:D131: [W18] "D  
A:E131: [W6] (E130+1)  
A:A132: [W24] \\_  
A:B132: [W18] \\_  
A:C132: [W18] \\_  
A:D132: [W18] \\_  
A:E132: [W6] (E131+1)  
A:E133: [W6] (E132+1)  
A:A134: [W24] ' Manganese (lb/hr)  
A:B134: [W18] "NEG.  
A:C134: [W18] "NEG.  
A:D134: (S2) [W18] (D13\*6.44/1000000) . . . . . From EPA 1988, See Page 4-156  
A:E134: [W6] (E133+1)  
A:A135: [W24] ' (TPY)  
A:B135: [W18] "NEG.  
A:C135: [W18] "NEG.  
A:D135: (S2) [W18] (D134\*240/2000)  
A:E135: [W6] (E134+1)  
A:E136: [W6] (E135+1)  
A:A137: [W24] ' Nickel (lb/hr)  
A:B137: [W18] "NEG.  
A:C137: [W18] "NEG.  
A:D137: (S2) [W18] (D13\*170/1000000) . . . . . From EPA 1988, See Page 4-158  
A:E137: [W6] (E136+1)  
A:A138: [W24] ' (TPY)  
A:B138: [W18] "NEG.  
A:C138: [W18] "NEG.  
A:D138: (S2) [W18] (D137\*240/2000)  
A:E138: [W6] (E137+1)



A:E139: [W6] (E138+1)  
A:A140: [W24] ' Cadmium (lb/hr)  
A:B140: [W18] "NEG.  
A:C140: [W18] "NEG.  
A:D140: (S2) [W18] (D13\*10.5/1000000) . . . . . From EPA 1988, See Page 4-159  
A:E140: [W6] (E139+1)  
A:A141: [W24] ' (TPY)  
A:B141: [W18] "NEG.  
A:C141: [W18] "NEG.  
A:D141: (S2) [W18] (D140\*240/2000)  
A:E141: [W6] (E140+1)  
A:E142: [W6] (E141+1)  
A:A143: [W24] ' Chromium (lb/hr)  
A:B143: [W18] "NEG.  
A:C143: [W18] "NEG.  
A:D143: (S2) [W18] (D13\*47.5/1000000) . . . . . From EPA 1988, See Page 4-160  
A:E143: [W6] (E142+1)  
A:A144: [W24] ' (TPY)  
A:B144: [W18] "NEG.  
A:C144: [W18] "NEG.  
A:D144: (S2) [W18] (D143\*240/2000)  
A:E144: [W6] (E143+1)  
A:E145: [W6] (E144+1)  
A:A146: [W24] ' Copper (lb/hr)  
A:B146: [W18] "NEG.  
A:C146: [W18] "NEG.  
A:D146: (S2) [W18] (D13\*280/1000000) . . . . . From EPA 1988, See Page 4-161  
A:E146: [W6] (E145+1)  
A:A147: [W24] ' (TPY)  
A:B147: [W18] "NEG.  
A:C147: [W18] "NEG.  
A:D147: (S2) [W18] (D146\*240/2000)  
A:E147: [W6] (E146+1)  
A:E148: [W6] (E147+1)  
A:A149: [W24] ' Vanadium (lb/hr)  
A:B149: [W18] "NEG.  
A:C149: [W18] "NEG.  
A:D149: (S2) [W18] (D13\*30\*2.324/1000000) . . . . . From EPA 1988, See Page 4-162; 2.324 pq/J = 1 lb/10<sup>6</sup> BTU  
A:E149: [W6] (E148+1)  
A:A150: [W24] ' (TPY)  
A:B150: [W18] "NEG.  
A:C150: [W18] "NEG.  
A:D150: (S2) [W18] (D149\*240/2000)  
A:E150: [W6] (E149+1)  
A:E151: [W6] (E150+1)  
A:A152: [W24] ' Selenium (lb/hr)  
A:B152: [W18] "NEG.  
A:C152: [W18] "NEG.  
A:D152: (S2) [W18] (D13\*10.1\*2.324/1000000) . . . . . From EPA 1988, See Page 4-162  
A:E152: [W6] (E151+1)

A:A153: [W24] ' (TPY)  
A:B153: [W18] "NEG.  
A:C153: [W18] "NEG.  
A:D153: (S2) [W18] (D152\*240/2000)  
A:E153: [W6] (E152+1)  
A:E154: [W6] (E153+1)  
A:A155: [W24] ' POM (lb/hr)  
A:B155: (S2) [W18] (\$B\$13\*0.48\*2.324/1000000) . . . . . From EPA 1988, See Page 4-161  
A:C155: (S2) [W18] (\$C\$13\*0.48\*2.324/1000000)  
A:D155: (S2) [W18] (\$D\$13\*0.12\*2.324/1000000)  
A:E155: [W6] (E154+1)  
A:A156: [W24] ' (TPY)  
A:B156: (S2) [W18] (B155\*8760/2000)  
A:C156: (S2) [W18] (C155\*3500/2000)  
A:D156: (S2) [W18] (D155\*240/2000)  
A:E156: [W6] (E155+1)  
A:E157: [W6] (E156+1)  
A:A158: [W24] ' Formaldehyde (lb/hr)  
A:B158: (S2) [W18] (\$B\$13\*38\*2.324/1000000) . . . . . From EPA 1988, See Page 4-156  
A:C158: (S2) [W18] (\$C\$13\*405/1000000)  
A:D158: (S2) [W18] (\$D\$13\*405/1000000)  
A:E158: [W6] (E157+1)  
A:A159: [W24] ' (TPY)  
A:B159: (S2) [W18] (B158\*8760/2000)  
A:C159: (S2) [W18] (C158\*3500/2000)  
A:D159: (S2) [W18] (D158\*240/2000)  
A:E159: [W6] (E158+1)  
A:A160: [W24] \  
A:B160: [W18] \  
A:C160: [W18] \  
A:D160: [W18] \  
A:E160: [W6] (E159+1)  
A:E161: [W6] (E160+1)  
A:E162: [W6] (E161+1)  
A:A165: [W24] 'Table A-5. Maximum Emissions for Additional Non-Regulated Pollutant  
A:E165: [W6] 165  
A:A166: [W24] ' for Cogeneration Project  
A:E166: [W6] (E165+1)  
A:A167: [W24] \  
A:B167: [W18] \  
A:C167: [W18] \  
A:D167: [W18] \  
A:E167: [W6] (E166+1)  
A:E168: [W6] (E167+1)  
A:A169: [W24] ^Pollutant  
A:B169: [W18] "Gas Turbine  
A:C169: [W18] "Duct Burner  
A:D169: [W18] "Gas Turbine  
A:E169: [W6] (E168+1)  
A:B170: [W18] "Natural Gas

A:C170: [W18] "Natural Gas  
A:D170: [W18] "No.2 Oil  
A:E170: [W6] (E169+1)  
A:A171: [W24] ^A  
A:B171: [W18] "B  
A:C171: [W18] "C  
A:D171: [W18] "D  
A:E171: [W6] (E170+1)  
A:A172: [W24] \\_  
A:B172: [W18] \\_  
A:C172: [W18] \\_  
A:D172: [W18] \\_  
A:E172: [W6] (E171+1)  
A:E173: [W6] (E172+1)  
A:A174: [W24] ' Antimony (lb/hr)  
A:B174: [W18] "NEG.  
A:C174: [W18] "NEG.  
A:D174: (S2) [W18] (\$D\$13\*9.4\*2.324/1000000) . . . . . From EPA 1979, See Page 137  
A:E174: [W6] (E173+1)  
A:A175: [W24] ' (TPY)  
A:B175: [W18] "NEG.  
A:C175: [W18] "NEG.  
A:D175: (S2) [W18] (D174\*240/2000)  
A:E175: [W6] (E174+1)  
A:E176: [W6] (E175+1)  
A:A177: [W24] ' Barium (lb/hr)  
A:B177: [W18] "NEG.  
A:C177: [W18] "NEG.  
A:D177: (S2) [W18] (\$D\$13\*8.4\*2.324/1000000) . . . . . From EPA 1979, See Page 137  
A:E177: [W6] (E176+1)  
A:A178: [W24] ' (TPY)  
A:B178: [W18] "NEG.  
A:C178: [W18] "NEG.  
A:D178: (S2) [W18] (D177\*240/2000)  
A:E178: [W6] (E177+1)  
A:E179: [W6] (E178+1)  
A:A180: [W24] ' Colbalt (lb/hr)  
A:B180: [W18] "NEG.  
A:C180: [W18] "NEG.  
A:D180: (S2) [W18] (\$D\$13\*3.9\*2.324/1000000) . . . . . From EPA 1979, See Page 137  
A:E180: [W6] (E179+1)  
A:A181: [W24] ' (TPY)  
A:B181: [W18] "NEG.  
A:C181: [W18] "NEG.  
A:D181: (S2) [W18] (D180\*240/2000)  
A:E181: [W6] (E180+1)  
A:E182: [W6] (E181+1)  
A:A183: [W24] ' Zinc (lb/hr)  
A:B183: [W18] "NEG.  
A:C183: [W18] "NEG.

A:D183: (S2) [W18] (\$D\$13\*294\*2.324/1000000) . . . . . From EPA 1979, See Page 137  
A:E183: [W6] (E182+1)  
A:A184: [W24] ' (TPY)  
A:B184: [W18] "NEG.  
A:C184: [W18] "NEG.  
A:D184: (S2) [W18] (D183\*240/2000)  
A:E184: [W6] (E183+1)  
A:E185: [W6] (E184+1)  
A:A186: [W24] ' Chlorine^a (lb/hr)  
A:B186: [W18] "NEG.  
A:C186: [W18] "NEG.  
A:D186: (S2) [W18] (D14\*0.5/1000000) . . . . . 0.5 ppm in Fuel Oil Assumed  
A:E186: [W6] (E185+1)  
A:A187: [W24] ' (TPY)  
A:B187: [W18] "NEG.  
A:C187: [W18] "NEG.  
A:D187: (S2) [W18] (D186\*240/2000)  
A:E187: [W6] (E186+1)  
A:A188: [W24] \  
A:B188: [W18] \  
A:C188: [W18] \  
A:D188: [W18] \  
A:E188: [W6] (E187+1)  
A:E189: [W6] (E188+1)  
A:A190: [W24] 'Source: EPA, 1979  
A:E190: [W6] (E189+1)  
A:A191: [W24] ' ^a Assumes 0.5 ppm in fuel oil.  
A:E191: [W6] (E190+1)

NOTE A

Volume is calculated based on ideal gas law:

$$\begin{aligned} \text{where: } PV &= mRT/M \\ P &= \text{pressure} = 2116.8 \text{ lb/ft}^2 \\ m &= \text{mass flow of gas (lb/hr)} \\ R &= \text{universal gas constant} = 1545 \\ M &= \text{molecular weight of gas} \\ T &= \text{temperature (K)} \end{aligned}$$

$$\begin{aligned} \text{Example: } V &= mRT/(MP) \text{ for natural gas} \\ &= 1,079,779 * 1,545 * (460 + 806) / 28.0323 / 2,116.8 / 60 \\ &= 593,208 \text{ ft}^3/\text{min} \end{aligned}$$

NOTE B

NO<sub>x</sub> is calculated by correcting to 15% O<sub>2</sub> dry conditions using ideal gas law and moisture and O<sub>2</sub> conditions.

Oxygen correction:

$$V_{\text{NOx (15\%)}} = \frac{V_{\text{NOx Dry}} * 5.9}{20.9 - \%O_2 \text{ Dry}}$$

$$V_{\text{NOx Dry}} = V_{\text{NOx (15\%)}} (20.9 - \%O_2 \text{ Dry}) / 5.9$$

$$\%O_2 \text{ Dry} = \%O_2 \text{ Act} / (1 - \%H_2O) ; \%O_2 \text{ Act} = \%O_2 \text{ Dry} (1 - \%H_2O)$$

$$V_{\text{NOx Act}} = V_{\text{NOx Dry}} (1 - \%H_2O)$$

Substituting:

$$V_{\text{NOx Act}} = V_{\text{NOx 15\%}} (20.9 - \%O_2 \text{ Dry}) (1 - \%H_2O) / 5.9$$

$$= V_{\text{NOx (15\%)}} [20.9 - (\%O_2 \text{ Act} / (1 - \%H_2O))] (1 - \%H_2O) / 5.9$$

$$= V_{\text{NOx (15\%)}} [20.9 (1 - \%H_2O) - \%O_2] / 5.9$$

$$\begin{aligned} m_{\text{NOx}} &= \frac{PVM_{\text{NOx}}}{RT} = \frac{V_{\text{NOx (15\%)}} [20.9 (1 - \%H_2O) - \%O_2] * P * M_{\text{NOx}}}{RT * 5.9} \end{aligned}$$

Example calculation for natural gas

$$\begin{aligned} m_{\text{NOx}} &= 25 * 593,208 [20.9 (1 - 0.1100) - 13.36] * 2,116.8 * 46 \\ &\quad * 60 * 1/10^6 / [(460 + 806) * 1,545 * 5.9] \\ &= 39.4 \text{ lb/hr} \end{aligned}$$

NOTE C

Same as D except only moisture correction is used:

$$V_{CO \text{ Act}} = V_{CO \text{ Dry}} (1 - \%H_2O)$$

$$\begin{aligned} m_{CO} &= PV_{CO \text{ Act}} M_{CO} / RT \\ &= PV_{CO \text{ Dry}} (1 - \%H_2O) M_{CO} / RT \end{aligned}$$

Example for natural gas

$$\begin{aligned} m_{CO} &= 42 * 593,208 * (1 - 0.1100) * 2,116.8 * 28 * 60 \\ &\quad / [1,545 * (460 + 806) * 10^6] \\ &= 40.3 \text{ lb/hr} \end{aligned}$$

## EMISSION FACTORS

EPA-450/2-88-006  
October 1988

# **Toxic Air Pollutant Emission Factors—A Compilation For Selected Air Toxic Compounds And Sources**

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October 1988



INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Nonylphenol production	2869	General	301	Phenol	108952	8.0 x 10E-4 lb/lb used	From engineering estimates	13
Nonylphenol production	2869	Fugitive	301	Phenol	108952	1.9 x 10E-4 lb/lb used	From engineering estimates	13
Nonylphenol production	2869	Storage	407084	Phenol	108952	1.0 x 10E-5 lb/lb used	From engineering estimates	13
Normal superphosphate production	2574	Curing building	30102806	Fluoride	16984488	3.8 lb/ton P2O5	Uncontrolled	97
Normal superphosphate production	2874	Mixer and den	30102805	Fluoride	16984488	0.2 lb/ton P2O5	Wet scrubber (97%)	97
Oil and coal combustion	49	Stack - particulate	102	Polychlorinated dibenzo-p-dioxins		68 ng/g	No penta homologue included, one location, TCDD detection = 20 ng/g	119
Oil and coal combustion	49	Stack - particulate	102	Tetrachlorodibenzo-p-dioxin, 2,3,7,8-	1746016	Not detectable	One location, detection limit = 10 ng/g	119
Oil combustion		Oil-fired boiler or furnace, util/commerc/industr/residential	1	Formaldehyde	50000	405 lb/10E12 Btu ✓	Uncontrolled, based on emissions testing	36
Oil combustion		Industrial, commercial, and residential boilers	1	Lead	7439921	8.9 lb/10E12 Btu ✓	Uncontrolled, calculated based on engineering judgement, assumed use distillate oil	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Manganese	7439965	26 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Manganese	7439965	11.96 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Manganese	7439965	5.72 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Manganese	7439965	2.86 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residential	1	Manganese	7439965	14 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residential	1	Manganese	7439965	6.44 lb/10E12 Btu ✓	Controlled with multiclone, calculated based on engineering	36

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
		al					Judgement	
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residential	1	Manganese	7439965	3.08 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residential	1	Manganese	7439965	1.54 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	3.2 lb/10E12 Btu	Uncontrolled, based on engineering judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	3.2 lb/10E12 Btu	Controlled by multiclone, based on engineering judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	2.4 lb/10E12 Btu	Controlled by ESP, based on engineering judgement	36
Oil combustion		Residual oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	0.83 lb/10E12 Btu	Controlled by scrubber, based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	3.0 lb/10E12 Btu	Uncontrolled, based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	3.0 lb/10E12 Btu	Controlled by multiclone, based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	2.25 lb/10E12 Btu	Controlled by ESP, based on engineering judgement	36
Oil combustion		Distillate oil-fired boiler, util/commerc/industr/residential	1	Mercury	7439976	0.78 lb/10E12 Btu	Controlled by scrubber, based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Nickel	7440020	1260 lb/10E12 Btu	Uncontrolled, based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Nickel	7440020	642.6 lb/10E12 Btu	Controlled by multiclone, based on engineering judgement	36

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
		al						
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residenti al	1	Nickel	7440020	352.8 lb/10E12 Btu	Controlled by ESP, based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residenti al	1	Nickel	7440020	50.4 lb/10E12 Btu	Controlled by scrubber, based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residenti al	1	Nickel	7440020	170 lb/10E12 Btu ✓	Uncontrolled, based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residenti al	1	Nickel	7440020	86.7 lb/10E12 Btu	Controlled by multiclone, based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residenti al	1	Nickel	7440020	47.6 lb/10E12 Btu	Controlled by ESP, based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residenti al	1	Nickel	7440020	6.8 lb/10E12 Btu	Controlled by scrubber, based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residenti al	1	Arsenic	7440382	19 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residenti al	1	Arsenic	7440382	4.2 lb/10E12 Btu ✓	Uncontrolled, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residenti al	1	Arsenic	7440382	2.06 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residenti al	1	Arsenic	7440382	0.50 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residenti al	1	Arsenic	7440382	0.42 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residenti al	1	Arsenic	7440382	9.31 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering	36

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
		al					Judgement	
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Arsenic	7440382	2.28 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Arsenic	7440382	1.90 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Beryllium	7440417	4.2 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residential	1	Beryllium	7440417	2.5 lb/10E12 Btu ✓	Uncontrolled, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residential	1	Beryllium	7440417	1.58 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residential	1	Beryllium	7440417	0.35 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residential	1	Beryllium	7440417	0.15 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Beryllium	7440417	2.65 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Beryllium	7440417	0.59 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Beryllium	7440417	0.25 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Cadmium	7440439	15.7 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residential	1	Cadmium	7440439	10.5 lb/10E12 Btu ✓	Uncontrolled, calculated based on engineering judgement	36

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		al Distillate oil-fired boilers, util/commerc/industr/residenti al	1	Cadmium	7440439	7.45 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residenti al	1	Cadmium	7440439	1.58 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residenti al	1	Cadmium	7440439	0.63 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residenti al	1	Cadmium	7440439	46.86 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residenti al	1	Cadmium	7440439	9.90 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residenti al	1	Cadmium	7440439	3.96 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residenti al	1	Chromium	7440473	21 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residenti al	1	Chromium	7440473	47.5 lb/10E12 Btu ✓	Uncontrolled, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residenti al	1	Chromium	7440473	27.8 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residenti al	1	Chromium	7440473	13.92 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residenti al	1	Chromium	7440473	3.84 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residenti al	1	Chromium	7440473	12.18 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering	36

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
		al					judgement	
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Chromium	7440473	6.09 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Chromium	7440473	1.68 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Copper	7440508	278 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residential	1	Copper	7440508	280 lb/10E12 Btu ✓	Uncontrolled, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residential	1	Copper	7440508	165.2 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residential	1	Copper	7440508	42 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Distillate oil-fired boilers, util/commerc/industr/residential	1	Copper	7440508	25.2 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Copper	7440508	165.2 lb/10E12 Btu	Controlled with multiclone, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Copper	7440508	42.0 lb/10E12 Btu	Controlled with ESP, calculated based on engineering judgement	36
Oil combustion		Residual oil-fired boilers, util/commerc/industr/residential	1	Copper	7440508	25.2 lb/10E12 Btu	Controlled with scrubber, calculated based on engineering judgement	36
Oil combustion		Utility boilers	101004	Lead	7439921	28 lb/10E12 Btu	Uncontrolled, calculated based on engineering judgement, assumed use residual oil	36
Oil combustion		Distillate watertube boilers	10300501	POM		40.12 pg/J heat input ✓	Uncontrolled	114

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion		Scotch marine boilers, distillate oil	10300501	PCN		17.7 pg/J	Uncontrolled	114
Oil combustion		Cast iron sectional boilers, distillate oil	10300501	PCN		<14.9 pg/J	Uncontrolled, home heating application	114
Oil combustion		Hot air furnace, distillate oil	10300501	PCN		<0.14 pg/J	Uncontrolled, same reference also lists <15.4 for same boiler/fuel type	114
Oil combustion	49	Boiler flue gas	1	Tetrachlorodibenzo-p-dioxin, 2,3,7,8-	1746016	Not detectable	Low ash, 2% sulfur oil, sampled after heat exch., before ESP, 2378-TCDD detec. limit=<4.2-<7.9 ng/m3	119
Oil combustion	49	Flue gas	1	Tetrachlorodibenzofuran, 2,3,7,8-	51207319	Not detectable	Low ash, 2% sulfur oil, sampled after heat exch., before ESP, 2378-TCDD detec. limit=<0.67-<1.3ng/m3	119
Oil combustion, commercial		Residual oil-fired tangential furnaces	103004	Vanadium	7440622	3660 pg/J	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, commercial		Residual oil-fired wall furnaces	103004	Vanadium	7440622	3660 pg/J	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, commercial		Tangential furnace, residual oil	103004	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Wall furnace, residual oil	103004	Selenium	7782492	10.1 pg/J ✓	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Scotch marine boilers, residual oil	10300401	PCN		0.95 pg/J heat input	Uncontrolled, represents benzo(a)pyrene only	114
Oil combustion, commercial		Distillate oil-fired tangential furnaces	103005	Vanadium	7440622	30.0 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Distillate oil-fired wall furnaces	103005	Vanadium	7440622	30.0 pg/J ✓	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, commercial		Tangential furnace, distillate oil	103005	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54

INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion, commercial		Wall furnace, distillate oil	103005	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, industrial		Tangential furnaces	102	Vanadium	7440622	260 pg/J	Controlled by scrubber, based on reported emissions and engineering judgement	54
Oil combustion, industrial		Tangential furnaces	102	Vanadium	7440622	1300 pg/J	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, industrial		Wall furnaces	102	Vanadium	7440622	260 pg/J	Controlled by scrubber, based on reported emissions and engineering judgement	54
Oil combustion, industrial		Wall furnaces	102	Vanadium	7440622	1300 pg/J	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, industrial		Tangential furnace	102	Selenium	7782492	2.0 pg/J	Controlled by scrubber, based on reported emissions data and engineering judgement	54
Oil combustion, industrial		Tangential furnace	102	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, industrial		Wall furnace	102	Selenium	7782492	2.0 pg/J	Controlled by scrubber, based on reported emissions data and engineering judgement	54
Oil combustion, industrial		Wall furnace	102	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, industrial		Steam atomized watertube, residual oil	10200401	PCM		2.3 pg/J heat input	Uncontrolled, represents mostly particulate PCM	114
Oil combustion, industrial		Watertube, residual oil	10200401	PCM		0.63 pg/J heat input	Uncontrolled, represents both gaseous and particulate PCM	114
Oil combustion, residential		Distillate oil-fired boilers		Vanadium	7440622	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, residential		Distillate oil-fired furnaces		Selenium	7782492	2.9 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54



INDUSTRIAL PROCESS	SIC CODE	EMISSION SOURCE	SCC	POLLUTANT	CAS NUMBER	EMISSION FACTOR	NOTES	REFERENCE
Oil combustion, utility		Wall-fired, residual oil	10100401	POM		3.9 pg/J heat input	Uncontrolled, ave. of 4 values ranging from 0.43-12.3 pg/J, represents gaseous & particulate POM	114
Oil combustion, utility		Face-fired, residual oil	10100401	POM		0.37 pg/J heat input	Uncontrolled, represents both gaseous and particulate POM	114
Oil combustion, utility		Tangential-fired, residual oil	10100404	POM		2.5 pg/J heat input	Cyclone controls, represents both gaseous and particulate POM	114
Oil combustion, utility	4911	Residual oil-fired tangential furnaces	101004	Vanadium	7440622	303 pg/J	Controlled by ESP, based on reported emissions and engineering judgement	54
Oil combustion, utility	4911	Residual oil-fired tangential furnaces	101004	Vanadium	7440622	1516 pg/J	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, utility	4911	Residual oil-fired wall furnaces	101004	Vanadium	7440622	303 pg/J	Controlled by ESP, based on reported emissions and engineering judgement	54
Oil combustion, utility	4911	Residual oil-fired wall furnaces	101004	Vanadium	7440622	1516 pg/J	Uncontrolled, based on reported emissions and engineering judgement	54
Oil combustion, utility	4911	Tangential, residual oil	101004	Selenium	7782492	2.0 pg/J	Controlled by ESP, based on reported emissions data and engineering judgement	54
Oil combustion, utility	4911	Tangential, residual oil	101004	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil combustion, utility	4911	Wall furnace, residual oil	101004	Selenium	7782492	2.0 pg/J	Controlled by ESP, based on reported emissions data and engineering judgement	54
Oil combustion, utility	4911	Wall furnace, residual oil	101004	Selenium	7782492	10.1 pg/J	Uncontrolled, based on reported emissions data and engineering judgement	54
Oil shale retorting	1311	Modified in situ retort		POM		3.3 g/hr	Based on offgas concentration and flow rate	114
Oil shale retorting	2911	Entire process		Mercury	7439976	2.2 x 10E-4 lbs/barrel oil produced	Includes Hg compound form, assumes fac. using 13,000 tons/day raw shale to prod. 12,000 bbl/day oil	40

PB81-225559

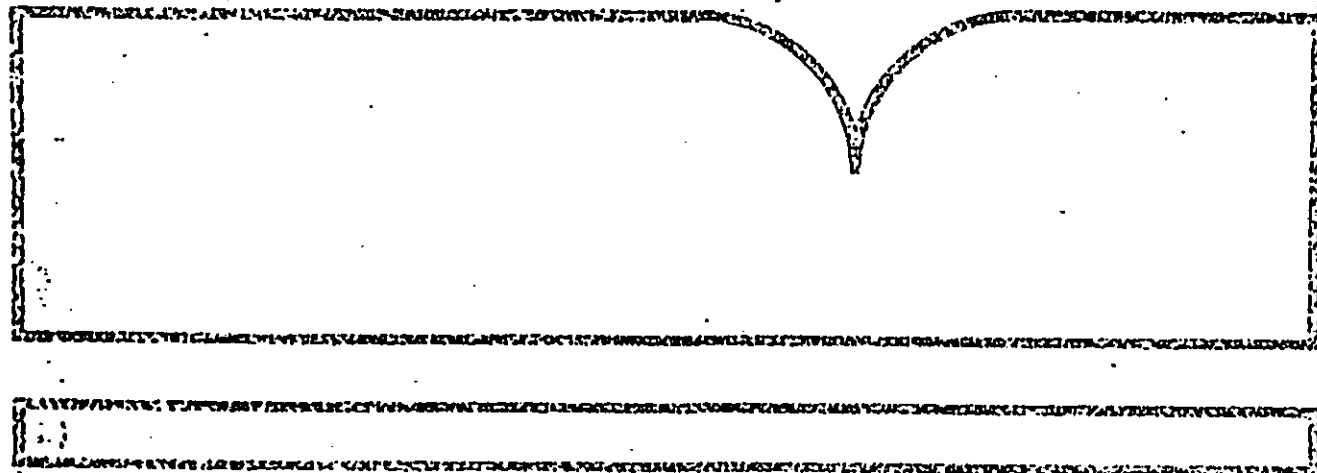
Emissions Assessment of Conventional Stationary  
Combustion Systems: Volume V: Industrial  
Combustion Sources

TRW, Inc.  
Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab.  
Research Triangle Park, NC

1981



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TABLE 61. COMPARISON OF EXISTING TRACE ELEMENT EMISSION FACTOR DATA  
WITH RESULTS OF CURRENT STUDY OF OIL-FIRED INDUSTRIAL  
COMBUSTION SOURCES, pg/)

Element	Distillate oil-fired boilers			Residual oil-fired boilers			
	Current study	Existing data		Current study	Existing data		
		Ref. 42	Ref. 43		Ref. 42	Ref. 21	Ref. 28
Aluminum (Al)	178	15	250	177	156	87	132
Arsenic (As)	3.5	1.3	1.5	1.2	9.1	18	12
Barium (Ba)	1.2	8.4	16	3.3	9.5	29	31
Calcium (Ca)	75	845	450	229	780	320	1428
Cadmium (Cd)	1.3	2.5	11	0.66	0.2	52	6.9
Cobalt (Co)	3.8	2.3	1.0	11	23	50	10
Chromium (Cr)	24	36	29	29	50	30	21
Copper (Cu)	37	205	160	10	93	64	350
Fluorine (F)	—	14	—	—	1.0	2.7	149
Iron (Fe)	383	545	140	83	379	411	453
Mercury (Hg)	—	1.7	1.2	—	1.9	0.9	1.5
Potassium (K)	85	60	230	261	213	777	392
Lithium (Li)	0.5	1.5	1.2	1.1	1.0	1.4	1.7
Magnesium (Mg)	42	40	210	24	111	297	2384
Nickel (Ni)	255	112	290	728	804	964	433
Lead (Pb)	24	48	42	2	7	80	34
Antimony (Sb)	—	1.7	5.7	—	21	10	25
Silicon (Si)	735	173	—	8655	1610	400	595
Vanadium (V)	195	30	2.9	366	250	3656	714
Zinc (Zn)	42	40	110	33	46	29	66

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**Prepared for**

**Industrial Environmental Research Lab, Research Triangle Park, NC**

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TABLE 52. COMPARISON OF TRACE ELEMENT EMISSION FACTORS FOR DISTILLATE OIL-FUELED GAS TURBINES AND DISTILLATE OIL ENGINES

Trace Element	Mean Emission Factor, pg/J	
	Distillate Oil Fueled Gas Turbine	Distillate Oil Reciprocating Engine
Aluminum	64	66
Antimony	9.4	12
Arsenic	2.1	2.2
Barium	8.4	14
Beryllium	0.14	0.03
Boron	28	11
Bromine	1.8	4.0
Cadmium	1.8	3.1
Calcium	330	237
Chromium	20	26
Cobalt	3.9	5.7
Copper	578	453
Iron	256	325
Lead	25	26
Magnesium	100	44
Manganese	145	16
Mercury	0.39	0.13
Molybdenum	3.6	12.5
Nickel	526	564
Phosphorus	127	97
Potassium	185	179
Selenium	2.3	2.1
Silicon	575	301
Sodium	590	1625
Tin	35	9.1
Vanadium	1.9	0.95
Zinc	294	178