KBN

April 3, 1992

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

RE: Polk County - A.P.
Polk Power Partners, L.P., d/b/a Polk Power Partners, L.P., Ltd.
Mulberry Cogeneration Project

Dear Clair:

Please find enclosed five copies of air construction permit application and prevention of significant deterioration analysis for an integrated congeneration facility. The facility will consist of a cogeneration power plant and a carbon dioxide (CO_2) recovery plant. A fee of $15,000 is enclosed to cover the appropriate permit fees for both facilities. The computer printouts of the air quality modeling results are being sent under separate cover.

I will be contacting you in a few weeks to review the initial comments your staff my have. In the meantime please call if you have any questions.

Sincerely,

Kennard F. Kosky

Kennard F. Kosky, P.E.
President

KFK/tyf

cc: William Malenius, Ark Energy, Inc.
Ward Marshall, Central and South West Services, Inc.
Barry Andrews, FDER
File (2)

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

FEDERAL EXPRESS

QUESTIONS? CALL 800-238-5355 TOLL FREE.

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AIRBILL
PACKAGE TRACKING NUMBER 1028818405

RECIPIENT'S COPY

Date	4-3-92

1 From (Your Name) Please Print: Robert C. McCann, Jr.
Your Phone Number (Very Important): (904) 331-9000
Company: KBN ENG & APPLIED SCIENCES
Department/Floor No.:
Street Address: 1034 NW 57TH ST
City: GAINESVILLE
State: FL
ZIP Required: 32605

2 To (Recipient's Name) Please Print: Clair Fancy
Recipient's Phone Number (Very Important): (904) 488-1344
Company: FL Dept. of Environmental Regulation
Department/Floor No:
Exact Street Address (We Cannot Deliver to P.O. Boxes or P.O. Zip Codes.): 2600 Blair Stone Road Room 238
City: Tallahassee
State: FL
ZIP Required: 32399-2400

YOUR INTERNAL BILLING REFERENCE INFORMATION (First 24 characters will appear on invoice.): Project 91193-0200

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Street Address:
City:
State:
ZIP Required:

3 PAYMENT 1 ☒ Bill Sender 2 ☐ Bill Recipient's FedEx Acct No 3 ☐ Bill 3rd Party FedEx Acct No 4 ☐ Bill Credit Card
5 ☐ Cash/Check

4 SERVICES (Check only one box)

Priority Overnight (Delivery by next business morning†)
- 11 ☐ YOUR PACKAGING
- 16 ☐ FEDEX LETTER *
- 12 ☐ FEDEX PAK *
- 13 ☒ FEDEX BOX
- 14 ☐ FEDEX TUBE

Standard Overnight (Delivery by next business afternoon†)
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Freight Service (for Extra Large or any package over 150 lbs.)
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*Declared Value Limit $100
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5 DELIVERY AND SPECIAL HANDLING (Check services required)
- 1 ☐ HOLD FOR PICK-UP (Fill in Box H)
- 2 ☒ DELIVER WEEKDAY
- 3 DELIVER SATURDAY (Extra charge) (Not available to all locations) ☐
- 4 ☐ DANGEROUS GOODS (Extra charge)
- 5 ☐
- 6 ☐ DRY ICE ____ Lbs.
- 7 ☐ OTHER SPECIAL SERVICE
- 8 ☐
- 9 ☐ SATURDAY PICK-UP (Extra charge)
- 10 ☐
- 11 ☐ DESCRIPTION
- 12 ☐ HOLIDAY DELIVERY (If offered) (Extra charge)

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APR 6 1992
Division of [illegible] Resources Management

6
PACKAGES	WEIGHT In Pounds Only
Total 1	Total 16

DIM SHIPMENT (Chargeable Weight)
☐ ____ lbs.
L x W x H = ____

Received At
1 ☐ Regular Stop 3 ☐ Drop Box
4 ☐ B.S.C.
2 ☐ On-Call Stop 5 ☐ Station

Emp. No. | Date
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City State Zip
Received By
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Date/Time Received FedEx Employee Number

7 Release Signature

FedEx Emp. No. Date/Time

Federal Express Use	
Base Charges	
Declared Value Charge	
Other 1	
Other 2	
Total Charges	

REVISION DATE 4/91
PART #137204 FXEM 6/91
FORMAT #082

082

ARK/CSW DEVELOPMENT PARTNERSHIP

1036

VENDOR NO.	DATE	AMOUNT
288	3/16/92	$7500.00

FLORIDA DEPT. OF ENVIRONMENTAL REGULATIONS
(APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES)

ARK/CSW DEVELOPMENT PARTNERSHIP
PH. 714-588-3767
23293 S. POINTE DRIVE
LAGUNA HILLS, CA 92653

SECURITY PACIFIC BANK
IRVINE COMMERCIAL CENTER OFFICE 0732
NEWPORT BEACH, CA 92660
16-4-1220

1036

**********SEVEN THOUSAND FIVE HUNDRED AND NO/100*****************

DATE	AMOUNT
3/16/92	$7,500.00

PAY TO THE ORDER OF FLORIDA DEPT. OF ENVIRONMENTAL REGULATIONS

⑈001036⑈ ⑆122000043⑆ 732⑈193995⑈

ARK/CSW DEVELOPMENT PARTNERSHIP

1048

VENDOR NO.	DATE	AMOUNT
288	3/24/92	$7,500.00

FLORIDA DEPT. OF ENVIRONMENTAL REGULATION

"APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES"

90L031

ARK/CSW DEVELOPMENT PARTNERSHIP
PH. 714-588-3767
23293 S. POINTE DRIVE
LAGUNA HILLS, CA 92653

SECURITY PACIFIC BANK
IRVINE COMMERCIAL CENTER OFFICE 0732
NEWPORT BEACH, CA 92660
16-4-1220

1048

****************SEVEN THOUSAND FIVE HUNDRED DOLLARS AND NO/100*************

DATE	AMOUNT
3/24/92	$7,500.00

PAY TO THE ORDER OF FLORIDA DEPT. OF ENVIRONMENTAL REGULATION

Anthony J. Williams

⑈001048⑈ ⑆122000043⑆732⑈193995⑈

R# 180758
#750^{00}
211670
AC53-~~211669~~
PSD-FL-187

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: *Cogeneration Power Plant* [x] New[1] [ ] Existing[1]

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

COMPANY NAME: *Polk Power Partners, L.P., d/b/a Polk Power Partners, L.P., Ltd.* COUNTY: *Polk*

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) *Cogen Power Plant*

SOURCE LOCATION: Street *County Road 555* City *3.7 miles SW of Bartow*

UTM: East *413.6 km Zone 17* North *3080.6 km*

Latitude *27* ° *50* ' *56.0*"N Longitude *81* ° *52* ' *38.9*"W

APPLICANT NAME AND TITLE: *William R. Malenius, Senior Program Manager*

APPLICANT ADDRESS: *23293 South Pointe Drive, Laguna Hills, California 92653*

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of *Polk Power Partners, L.P.*

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

*Attach letter of authorization

Signed: Wm Malenius

William R. Malenius, Senior Program Manager
Name and Title (Please Type)

Date: *4/2/92* Telephone No. *(714) 588-3767*

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.) This is to certify that the engineering features of this pollution control project have been ~~designed~~/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgement, that

---

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

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

Signed

Kennard F. Kosky
Name (Please Type)

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

1034 N.W. 57th Street, Gainesville, FL 32605
Mailing Address (Please Type)

Florida Registration No. *14996* Date: *4/2/92* 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 and operation of integrated cogeneration facility. The power plant consists of one combustion turbine, an associated heat recovery steam generator (HRSG), and a secondary HRSG with duct burner. See Sections 1.0 and 2.0 in PSD Application.

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

Start of Construction *10/1/92* Completion of Construction *9/1/94*

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 overall design of the project. Dry low-NO_x combustion technology and water injection will be used to reduce air pollutant emissions.

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

No previous DER permits.

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

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

1. Is this source in a non-attainment area for a particular pollutant? *No*
   a. If yes, has "offset" been applied? ____________
   b. If yes, has "Lowest Achievable Emission Rate" been applied? ____________
   c. If yes, list non-attainment pollutants. ____________
2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. *Yes*[a]
3. Does the State "Prevention of Significant Deterioration" (PSD) requirement apply to this source? If yes, see Sections VI and VII. *Yes*[b]
4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? *Yes*[c]
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 attached. Full responses can be found as follows:***

[a] *Section 4.0*
[b] *Section 3.0*
[c] *Section 4.0*

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

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

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		
	Not Applicable			

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

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 Tables 2-1 and 2-2 in PSD Application*

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
SO_2	*105.7(0.3)*	*416.5(1.3)*	*0.8% Sulfur*	*845.6*	*105.7(0.3)*	*416.5(1.3)*	*See*
PM	*15.0(1.0)*	*65.7(4.3)*	*NA*	*NA*	*15.0(1.0)*	*65.7(4.3)*	*Figure 2-1*
NO_x	*182.2(15.8)*	*718.2(69.4)*	*93 ppmvd*	*403.4*	*182.2(15.8)*	*718.2(69.4)*	*in PSD*
CO	*82.6(9.9)*	*329.9(43.4)*	*NA*	*NA*	*82.6(9.9)*	*329.9(43.4)*	*Application*
VOC	*10.11(3.0)*	*40.4(13.0)*	*NA*	*NA*	*10.11(3.0)*	*40.4(13.0)*	

[1] See Section V, Item 2. *Maximum at 20°F; Actual at 59°F; Secondary HRSG Duct Burner Emissions shown in parentheses.*

[2] Reference applicable emission standards and units (e.g. Rule 17-2.600(5)(b)2. Table II, E. (1) - 0.1 pounds per million BTU heat input)*NSPS - 0.8% Sulfur Fuel Oil and 75 ppmvd NO_x corrected to 15% O_2 and heat rate at ISO conditions. FDER Rule 17-2.660 40 CFR Part 60 Subpart GG.*

[3] Calculated from operating rate and applicable standard.

[4] Emission, if source operated with~~out~~ control (See Section V, Item 3).

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

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

E. Fuels

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	
Natural Gas--CT	*914.5 MCF/hr*	*1,013.4 MCF/hr*	*962.8*
Distillate Oil--CT	*50,044.5 lb/hr*	*55,604 lb/hr*	*1,031.5*
Propane--CT	*997.7 MCF/hr*	*1,104.2 MCF/hr*	*1,049.0*
Natural Gas--DB	*104.2 MCF/hr*	*104.2 MCF/hr*	*99*

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

Fuel Analysis:

Percent Sulfur: *Natural gas & propane--1 grain/100 CF; Oil--0.1%* Percent Ash: *<0.01% WGT*

Density: *7.1* lbs/gal Typical Percent Nitrogen: *0.03% WGT*

Heat Capacity: *Gas--19,303; propane--19,910; oil--18,550* BTU/lb *131,700* BTU/gal

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

F. If applicable, indicate the percent of fuel used for space heating. *Not applicable*

Annual Average *N.A.* Maximum *N.A.*

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

Plant will be designed for zero wastewater discharge. Solid wastes will be disposed of in an approved manner.

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

Stack Height: 125 ft. Stack Diameter: 15.0 ft.

Gas Flow Rate: 753,740 ACFM 532,987 DSCFM Gas Exit Temperature: 220 °F.

Water Vapor Content: 7.3 % Velocity: 71.1 FPS

See Tables A-1, A-6 and A-11 in Appendix A of PSD application. Data for distillate oil at 20°F shown above (maximum emission case). Does not include flow reduction with diversion to CO_2 recovery plant.

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

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

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

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

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

[ ] Other (specify) ____________

Brief description of operating characteristics of control devices: ____

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

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

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]
   Not Applicable
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods, 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made.
   See Tables A-1 through A-15 in PSD application.
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   See Tables A-1 through A-15 in 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 Sections 2.0 and 4.0 in PSD application and Tables A-6 and A-11.
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency).
   Manufacturers' guarantees form the basis of emission estimates (see Tables A-1 through A-15 in PSD application).
6. An 8 ½" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained.
   See Figure 2-1 in PSD application.
7. An 8 ½" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Examples: Copy of relevant portion of USGS topographic map).
   See Figure 1-1 in PSD application.
8. An 8 ½" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   See Figure 1-2 in PSD application.

9. The appropriate application fee in accordance with Rule 17-4.05. The check should be made payable to the Department of Environmental Regulation.
Applicable fee is 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. *Not Applicable*

SECTION VI: BEST AVAILABLE CONTROL TECHNOLOGY

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

[*X*] Yes [ ] No

Contaminant	Rate or Concentration
NO_x - oil firing	*93 ppmvd corrected to 15% O_2 heat rate & nitrogen content*
- natural gas firing	*96 ppmvd corrected to 15% O_2 and heat rate*
SO_2	*0.8% sulfur fuel*

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

[*X*] Yes [ ] No

Contaminant	Rate or Concentration
See Section 4.0 in PSD application	

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

Contaminant	Rate or Concentration
See Sections 2.0 and 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

5. Useful Life: 6. Operating Costs:

7. Energy: 8. Maintenance Cost:

9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft. b. Diameter ft.

c. Flow Rate: ACFM d. Temperature: °F.

e. Velocity: FPS

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

1.

a. Control Devices: b. Operating Principles:

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

e. Useful Life: f. Operating Cost:

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

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

2.

a. Control Device: b. Operating Principles:

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

e. Useful Life: f. Operating Cost:

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

i. Availability of construction materials and process chemicals:

---

[1] Explain method of determining efficiency.

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

j. Applicability to manufacturing processes:

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

3.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

4.

a. Control Device:

b. Operating Principles:

c. Efficiency:[1]

d. Capital Cost:

e. Useful Life:

f. Operating Cost:

g. Energy:[2]

h. Maintenance Cost:

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

F. Describe the control technology selected:

1. Control Device:

2. Efficiency:[1]

3. Capital Cost:

4. Useful Life:

5. Operating Cost:

6. Energy:[2]

7. Maintenance Cost:

8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City:

(4) State:

---

[1] Explain method of determining efficiency.
[2] Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

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

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

See Section 5.0 in PSD application

A. Company Monitored Data

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

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

Other data recorded ____________________

Attach all data or statistical summaries to this application.

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

2. Instrumentation, Field and Laboratory

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

b. Was instrumentation calibrated in accordance with Department procedures?

☐ Yes ☐ No ☐ Unknown

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

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

2. Surface data obtained from (location)______________________

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

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

C. Computer Models Used *See Section 6.1 in PSD application*

1. ______________________ Modified? If yes, attach description.

2. ______________________ Modified? If yes, attach description.

3. ______________________ Modified? If yes, attach description.

4. ______________________ Modified? If yes, attach description.

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

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

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

E. Emission Data Used in Modeling *See Section 6.0 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. *See PSD application*

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

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

R# 180758
$\$7500^{00}$

AC53-211670
PSD-FL-187

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

APPLICATION TO OPERATE/CONSTRUCT AIR POLLUTION SOURCES

SOURCE TYPE: *CO$_2$ Recovery Plant* [*X*] New[1] [ ] Existing[1]

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

COMPANY NAME: *Polk Power Partners, L.P., d/b/a Polk Power Partners, L.P., Ltd.* COUNTY: *Polk*

Identify the specific emission point source(s) addressed in this application (i.e., Lime Kiln No. 4 with Venturi Scrubber; Peaking Unit No. 2, Gas Fired) *CO$_2$ Recovery Vents (2)*

SOURCE LOCATION: Street *County Road 555* City *3.7 miles SW of Bartow*

UTM: East *413.6 km; zone 17* North *3080.6 km*

Latitude *27* ° *50* ' *56.0* "N Longitude *81* ° *52* ' *38.9* "W

APPLICANT NAME AND TITLE: *William R. Malenius, Senior Program Manager*

APPLICANT ADDRESS: *23293 South Pointe Drive, Laguna Hills, California 92653*

SECTION I: STATEMENTS BY APPLICANT AND ENGINEER

A. APPLICANT

I am the undersigned owner or authorized representative* of *Polk Power Partners, L.P.*

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

*Attach letter of authorization

Signed:

William R. Malenius, Senior Program Manager
Name and Title (Please Type)

Date: *04/02/92* Telephone No. *(714) 588-3767*

B. PROFESSIONAL ENGINEER REGISTERED IN FLORIDA (where required by Chapter 471, F.S.) This is to certify that the engineering features of this pollution control project have been ~~designed~~/examined by me and found to be in conformity with modern engineering principles applicable to the treatment and disposal of pollutants characterized in the permit application. There is reasonable assurance, in my professional judgement, that

---

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

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

Signed ____________________

Kennard F. Kosky
Name (Please Type)

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

1034 N.W. 57th Street, Gainesville, FL 32605
Mailing Address (Please Type)

Florida Registration No. *14996* Date: *04/02/92* 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 and operation of an integrated cogeneration facility. The CO_2 recovery plant consists of CO_2 absorption and processing. Liquid CO_2 of beverage and food quality and dry ice will be produced; 150 tons per day will be the maximum CO_2 produced. See Sections 1.0 and 2.0 in PSD application.

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

Start of Construction *10/01/92* Completion of Construction *09/01/94*

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.)

Scrubber for amine solvent is estimated at $240,600.

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

No previous DER permits.

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

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

1. Is this source in a non-attainment area for a particular pollutant? *No*
   a. If yes, has "offset" been applied? ______
   b. If yes, has "Lowest Achievable Emission Rate" been applied? ______
   c. If yes, list non-attainment pollutants. ______
2. Does best available control technology (BACT) apply to this source? If yes, see Section VI. *Yes*[a]
3. Does the State "Prevention of Significant Deterioration" (PSD) requirement apply to this source? If yes, see Sections VI and VII. *Yes*[b]
4. Do "Standards of Performance for New Stationary Sources" (NSPS) apply to this source? *Yes*[c]
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 attached. Full responses can be found as follows:

[a] *Section 4.0.*
[b] *Section 3.0.*
[c] *Section 4.0.*

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

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

Description	Contaminants		Utilization Rate - lbs/hr	Relate to Flow Diagram
	Type	% Wt		
FS-1 Solvent	*VOC*	*85*	*Recirculating scrubber*	*See Figure 2-2*

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 2-2 in PSD application

Name of Contaminant	Emission[1]		Allowed[2] Emission Rate per Rule 17-2	Allowable[3] Emission lbs/hr	Potential[4] Emission		Relate to Flow Diagram
	Maximum lbs/hr	Actual T/yr			lbs/hr	T/yr	
SO_2	*5.17*	*22.27*	*NA*	*NA*	*5.17*	*22.27*	*see*
PM	*6.68*	*29.54*	*NA*	*NA*	*6.68*	*29.54*	*Figure*
NO_x	*24.23*	*105.53*	*NA*	*NA*	*24.23*	*105.53*	*2-2 in*
CO	*13.70*	*59.97*	*NA*	*NA*	*13.70*	*59.97*	*PSD*
VOC	*18.17*	*79.58*	*NA*	*NA*	*18.17*	*79.58*	*App.*

[1] See Section V, Item 2. *Emissions from combustion turbine (CT) and duct burner (DB) included.*

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

[3] Calculated from operating rate and applicable standard.

[4] Emission, if source operated with~~out~~ control (See Section V, Item 3).

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

Name and Type (Model & Serial No.)	Contaminant	Efficiency	Range of Particles Size Collected (in microns) (If applicable)	Basis for Efficiency (Section V Item 5)
Packed tower	*VOC*	*90%*	*N.A.*	*Manufacturer*
(scrubber)				*estimate*

E. Fuels *All energy used in CO_2 recovery plant is derived from cogeneration power plant.*

Type (Be Specific)	Consumption*		Maximum Heat Input (MMBTU/hr)
	avg/hr	max./hr	

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

Fuel Analysis:

Percent Sulfur:________ Percent Ash:________

Density: ________ lbs/gal Typical Percent Nitrogen:________

Heat Capacity:________ BTU/lb ________ BTU/gal

Other Fuel Contaminants (which may cause air pollution):________

F. If applicable, indicate the percent of fuel used for space heating. *Not Applicable*

Annual Average ________ Maximum ________

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

Plant will be designed for zero wastewater discharge. Solid wastes will be disposed of in an approved manner.

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

Stack Height: *170* ft. Stack Diameter: *3.0* ft.

Gas Flow Rate: *28,202* ACFM *22,620* DSCFM Gas Exit Temperature: *117* °F.

Water Vapor Content: *approximately 11* % Velocity: *66.5* FPS

SECTION IV: INCINERATOR INFORMATION

Not Applicable

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

Description of Waste ______

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

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

Manufacturer ______

Date Constructed ______ Model No. ______

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

Stack Height: ______ ft. Stack Diameter: ______ Stack Temp. ______

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

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

Type of pollution control devices: ☐ Cyclone ☐ Wet Scrubber ☐ Afterburner

☐ Other (specify) ______

Brief description of operating characteristics of control devices: ______

______

______

______

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

______

______

______

______

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

SECTION V: SUPPLEMENTAL REQUIREMENTS

Please provide the following supplements where required for this application.

1. Total process input rate and product weight -- show derivation [Rule 17-2.100(127)]
   Not applicable
2. To a construction application, attach basis of emission estimate (e.g., design calculations, design drawings, pertinent manufacturer's test data, etc.) and attach proposed methods (e.g., FR Part 60 Methods, 1, 2, 3, 4, 5) to show proof of compliance with applicable standards. To an operation application, attach test results or methods used to show proof of compliance. Information provided when applying for an operation permit from a construction permit shall be indicative of the time at which the test was made.
   See Section 2.0 in PSD application.
3. Attach basis of potential discharge (e.g., emission factor, that is, AP42 test).
   See Section 2.0 in 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 Section 4.0 in PSD application.
5. With construction permit application, attach derivation of control device(s) efficiency. Include test or design data. Items 2, 3 and 5 should be consistent: actual emissions = potential (1-efficiency).
   See Section 4.0 in PSD application.
6. An 8 ½" x 11" flow diagram which will, without revealing trade secrets, identify the individual operations and/or processes. Indicate where raw materials enter, where solid and liquid waste exit, where gaseous emissions and/or airborne particles are evolved and where finished products are obtained.
   See Figure 2-2 in PSD application.
7. An 8 ½" x 11" plot plan showing the location of the establishment, and points of airborne emissions, in relation to the surrounding area, residences and other permanent structures and roadways (Examples: Copy of relevant portion of USGS topographic map).
   See Figure 1-1 in PSD application.
8. An 8 ½" x 11" plot plan of facility showing the location of manufacturing processes and outlets for airborne emissions. Relate all flows to the flow diagram.
   See Figure 1-2 in PSD application.

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

[ ] Yes [*X*] No

Contaminant	Rate or Concentration

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

[*X*] Yes[a] [ ] No [a]*In general*

Contaminant	Rate or Concentration

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

Contaminant	Rate or Concentration
VOC	*90% removal*
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

5. Useful Life:
6. Operating Costs:
7. Energy:
8. Maintenance Cost:
9. Emissions:

Contaminant	Rate or Concentration

10. Stack Parameters

a. Height: ft.
b. Diameter ft.
c. Flow Rate: ACFM
d. Temperature: °F.
e. Velocity: FPS

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

1.

a. Control Devices:
b. Operating Principles:
c. Efficiency:[1]
d. Capital Cost:
e. Useful Life:
f. Operating Cost:
g. Energy:[2]
h. Maintenance Cost:
i. Availability of construction materials and process chemicals:
j. Applicability to manufacturing processes:
k. Ability to construct with control device, install in available space, and operate within proposed levels:

2.

a. Control Device:
b. Operating Principles:
c. Efficiency:[1]
d. Capital Cost:
e. Useful Life:
f. Operating Cost:
g. Energy:[2]
h. Maintenance Cost:
i. Availability of construction materials and process chemicals:

[1] Explain method of determining efficiency.
[2] Energy to be reported in units of electrical power - KWH design rate.

j. Applicability to manufacturing processes:

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

3.

a. Control Device: b. Operating Principles:

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

e. Useful Life: f. Operating Cost:

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

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

4.

a. Control Device: b. Operating Principles:

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

e. Useful Life: f. Operating Cost:

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

i. Availability of construction materials and process chemicals:

j. Applicability to manufacturing processes:

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

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

1. Control Device: 2. Efficiency:[1]

3. Capital Cost: 4. Useful Life:

5. Operating Cost: 6. Energy:[2]

7. Maintenance Cost: 8. Manufacturer:

9. Other locations where employed on similar processes:

a. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

---

[1] Explain method of determining efficiency.
[2] Energy to be reported in units of electrical power - KWH design rate.

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

b. (1) Company:

(2) Mailing Address:

(3) City: (4) State:

(5) Environmental Manager:

(6) Telephone No.:

(7) Emissions:[1]

Contaminant	Rate or Concentration

(8) Process Rate:[1]

10. Reason for selection and description of systems:

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

SECTION VII - PREVENTION OF SIGNIFICANT DETERIORATION

See Section 5.0 in PSD application

A. Company Monitored Data

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

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

Other data recorded ____

Attach all data or statistical summaries to this application.

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

2. Instrumentation, Field and Laboratory

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

b. Was instrumentation calibrated in accordance with Department procedures?

☐ Yes ☐ No ☐ Unknown

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

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

2. Surface data obtained from (location)______________________________

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

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

C. Computer Models Used ***See Section 6.0 in PSD application***

1. ______________________________ Modified? If yes, attach description.

2. ______________________________ Modified? If yes, attach description.

3. ______________________________ Modified? If yes, attach description.

4. ______________________________ Modified? If yes, attach description.

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

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

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

E. Emission Data Used in Modeling ***See Section 6.0 in PSD application***

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

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

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

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

1.0 INTRODUCTION

Polk Power Partners, L.P., d/b/a Polk Power Partners, L.P., Ltd., is proposing to construct and operate an integrated cogeneration facility at a 54.7-acre site. The facility is referred to as the Mulberry Cogeneration Facility. The Mulberry Cogeneration Facility is a combined cycle cogeneration power plant located approximately 3.7 miles southwest of the community of Bartow, Florida, on County Road 555 (see Figure 1-1).

The plant consists of one General Electric (GE) PG 7111EA combustion turbine, with a primary heat recovery steam generator (HRSG), a secondary HRSG, and one steam turbine generator. The facility will generate approximately 120,000 kilowatts (kW) net power to the transmission system at average ambient conditions. The primary fuel for the plant is natural gas; the plant is also capable of burning fuel oil or propane as the backup fuel. The combustion turbine (CT) uses specially designed combustors to limit nitrogen oxide (NO_x) emissions. Exhaust gas from the CT is ducted to the primary HRSG to produce steam which is used in the steam turbine to generate electrical power and to provide steam to the host carbon dioxide (CO_2) plant. The secondary HRSG takes a slipstream from the discharge of the primary HRSG. The slipstream is duct fired with natural gas to create additional high-pressure steam for the steam turbine. The exhaust gas of the secondary HRSG is rich in CO_2 and is ducted to the CO_2 plant thermal host as feed gas to the CO_2 stripping process. Approximately 150 tons per day (TPD) of liquid CO_2 is produced by the thermal host. Steam is provided to the CO_2 plant thermal host at a rate of 25,000 pounds per hour (lb/hr) at 105 pounds per square inch absolute (psia) and 341 degrees Fahrenheit (°F). Liquid CO_2 storage, handling, and dry ice production facilities are also on-site. General characteristics of the facility are presented in Table 1-1.

KBN Engineering and Applied Sciences, Inc. (KBN), has been contracted 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 <u>de minimis</u>

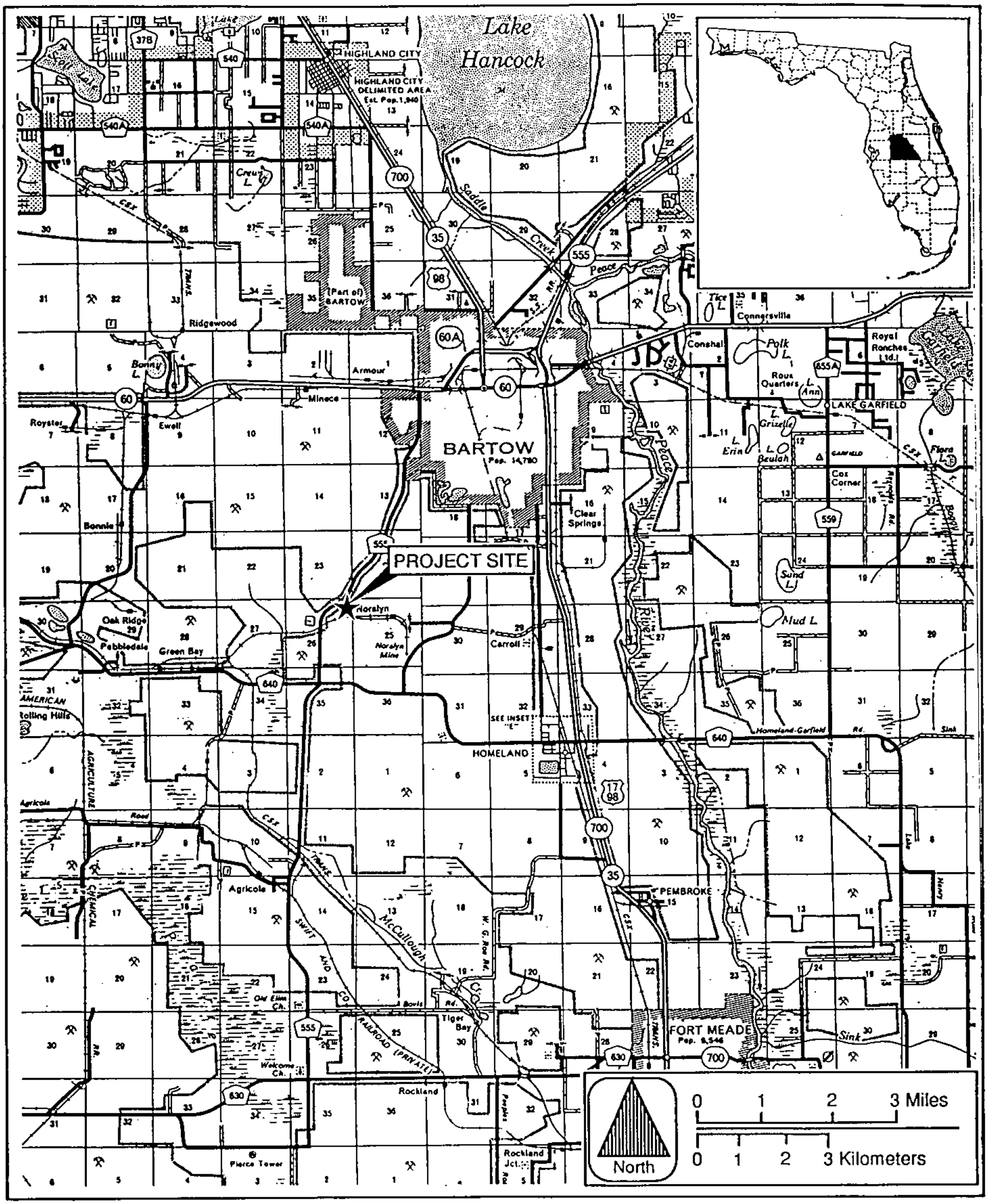


Figure 1-1 PROJECT LOCATION MAP

SOURCES: FDOT, 1988; KBN, 1992.

Table 1-1. Characteristics of the Mulberry Cogeneration Facility

Characteristic	Data
Nominal Capacity (MW)	
Combustion Turbine	81
Steam Cycle	45
Total	126
Auxiliary Loads	-3.5
Net Output	122.5
Equipment Characteristics	
Type of CT	GE PG 7111EA
Heat Input (MMBtu/hr)	859.3[a]
Number of HRSGs[b]	2
Number of Steam Turbines	1
Fuels	
Initial Operation (first 3 years)	Natural gas, distillate oil, and propane
Permanent Operation	Natural gas with distillate oil as backup
CO_2 Plant	
Capacity (TPD)	150
Solvent	Economic FS[c]-1
Trains	2
Process Steam Requirements (lb/hr)	25,000

Note:
CT = combustion turbine
GE = General Electric
HRSG = heat recovery steam generator

[a] Represents ISO conditions and firing natural gas.
[b] Main HRSG does not have supplemental firing; secondary HRSG will have a maximum firing rate of 99 MM Btu/hour and utilize only natural gas.
[c] Monoethanolamine (MEA) proprietary solution.

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 sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), particulate matter (PM), particulate matter with an aerodynamic diameter of 10 micrometers (PM10), volatile organic compounds (VOCs), sulfuric acid mist, beryllium (Be), and arsenic (As). Therefore, the project is subject to PSD review for these pollutants.

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

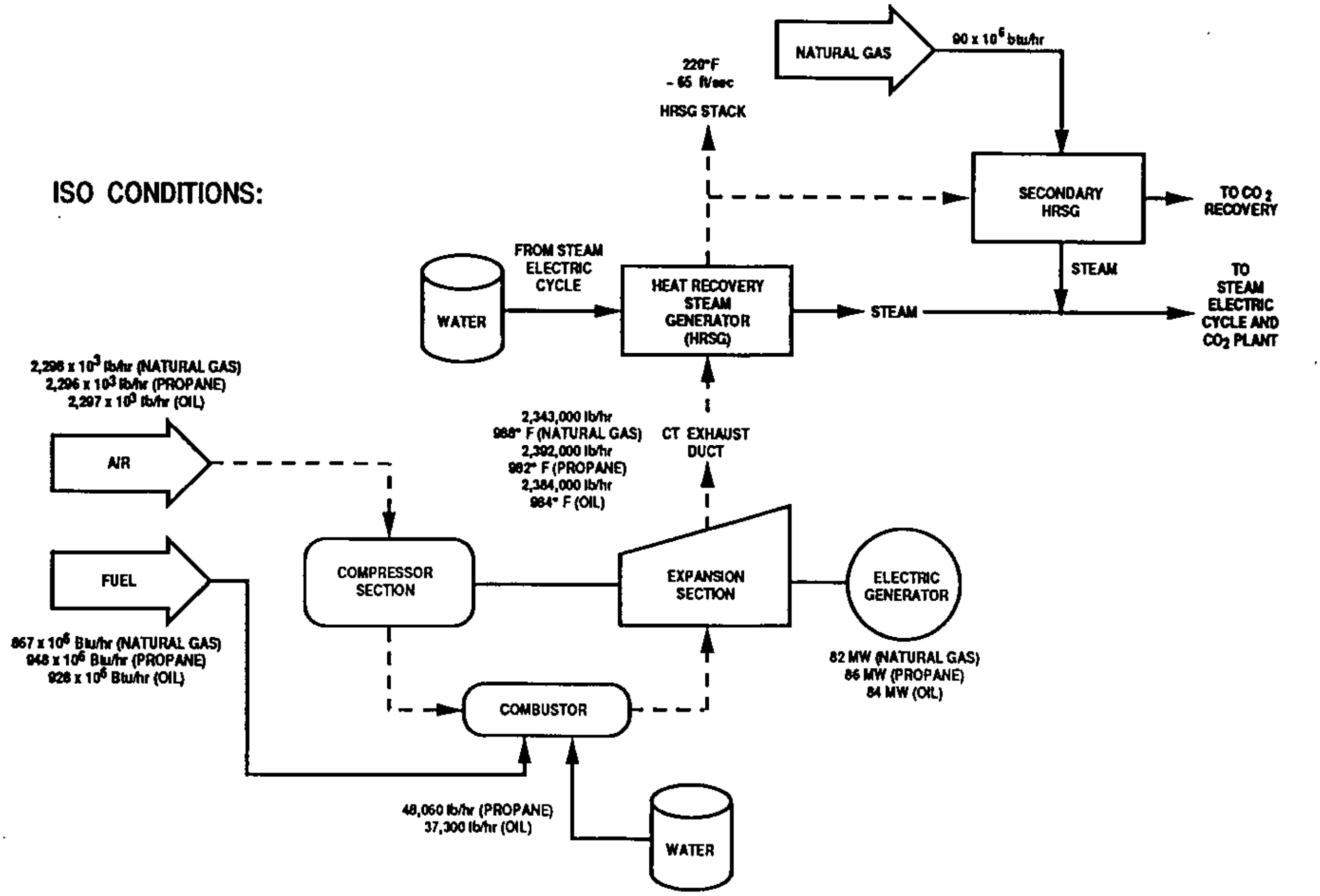
2.1 POWER PLANT DESCRIPTION

The proposed power plant will consist of one GE PG 7111EA combustion turbine. This CT is a heavy-frame industrial gas turbine that will use dry low-NOx combustion technology and water injection to control NO_x emissions. The CT combustion gases will exhaust through a HRSG and into a single stack. There will be no bypass for simple cycle operation. A flow diagram is presented in Figure 2-1. Stack, operating, and emission data for the proposed combustion turbines are presented in Table 2-1.

For the first 3 years of operation, the CT will be fired with natural gas, propane, and distillate oil. The amount of generation for each fuel will depend upon availability. After this period, natural gas will be the primary fuel with distillate use as backup (maximum of 30 days operation). The distillate oil will have a sulfur content of 0.1 percent or less. The main HRSG will not be supplementary fired.

The steam turbine is a single casing, condensing machine with an induction port to accept a portion of the steam. The steam turbine exhausts to a surface condenser served by a multicell cooling tower and circulating water pumps. Plant water for makeup to the cooling tower and steam cycle is obtained from two wells located on the site. The raw water is processed in a pretreatment system upstream of the demineralizer. A demineralizer system is used to treat the incoming water for makeup to the HRSG steam cycle. Wastewater from the plant is disposed of in a wastewater treatment system to meet the zero discharge requirements of the environmental permits. The wastewater treatment system consumes 5,300 lb/hr of steam (105 psia, 341°F). Natural gas is provided at the facility boundary and is pressurized in a fuel gas compressor to the pressure required by the combustion turbine generator. All systems in the plant are controlled from a central control room via a digital control system. The plant control room and office space are located adjacent to the steam turbine area. Figure 2-2 presents a plot plan of the facility.

KBN30/ARK ENERGY FLOW .2
4/2/92 ph



NOTE: SEE TABLE A-1 FOR DESIGN INFORMATION AND STACK PARAMETERS FOR EACH FUEL.

Figure 2-1 SIMPLIFIED FLOW DIAGRAM OF PROPOSED MULBERRY COGENERATION POWER PLANT

Table 2-1. Stack, Operating, and Emission Data for the Proposed Combustion Turbine [GE PG7111(EA)]

	Fuel Type[a]		
Parameter	Natural Gas	Fuel Oil	Propane
Stack Data (ft)			
Height	125	125	125
Diameter	15	15	15
Operating Data (ISO Conditions, i.e. 59°F)[b]			
Temperature (°F)	220	220	220
Velocity (ft/sec)	64.1	65.2	65.9
Maximum Hourly Emission Data (lb/hr) for Each Emission Unit/Fuel Type (20°F)[c]			
SO_2	2.9	105.7	3.2
PM	7.0	15.0	6.0
NO_x	97.5	182.2	177.8
CO	47.0	82.6	23.5
VOC	7.05	10.11	7.1
Pb	Neg.	0.0092	Neg.
Sulfuric Acid Mist	0.23	8.5	0.25
F	Neg.	0.0335	Neg.
Be	Neg.	0.00258	Neg.
Hg	Neg.	0.00309	Neg.
As	Neg.	0.00433	Neg.
Annual Potential Emission Data (TPY) for Each Emission Unit/Fuel Type (59°F)[c]			
SO_2	11.4	416.5	12.5
PM	30.7	65.7	26.8
NO_x	384.5	718.2	703.3
CO	187.8	329.9	94.0
VOC	28.2	40.4	28.2
Pb	Neg.	0.036	Neg.
Sulfuric Acid Mist	0.9	33.6	1.0
F	Neg.	0.132	Neg.
Be	Neg.	0.0102	Neg.
Hg	Neg.	0.0122	Neg.
As	Neg.	0.0171	Neg.

Note: Neg. = negligible emissions for applicable pollutant.

[a] Refer to Appendix A for detailed information on each fuel.
[b] Does not account for exhaust flow diverted to the CO_2 plant.
[c] Other regulated pollutants are assumed to have negligible emissions. These pollutants include reduced sulfur compounds, hydrogen sulfide, asbestos, vinyl chloride, and radionuclides.

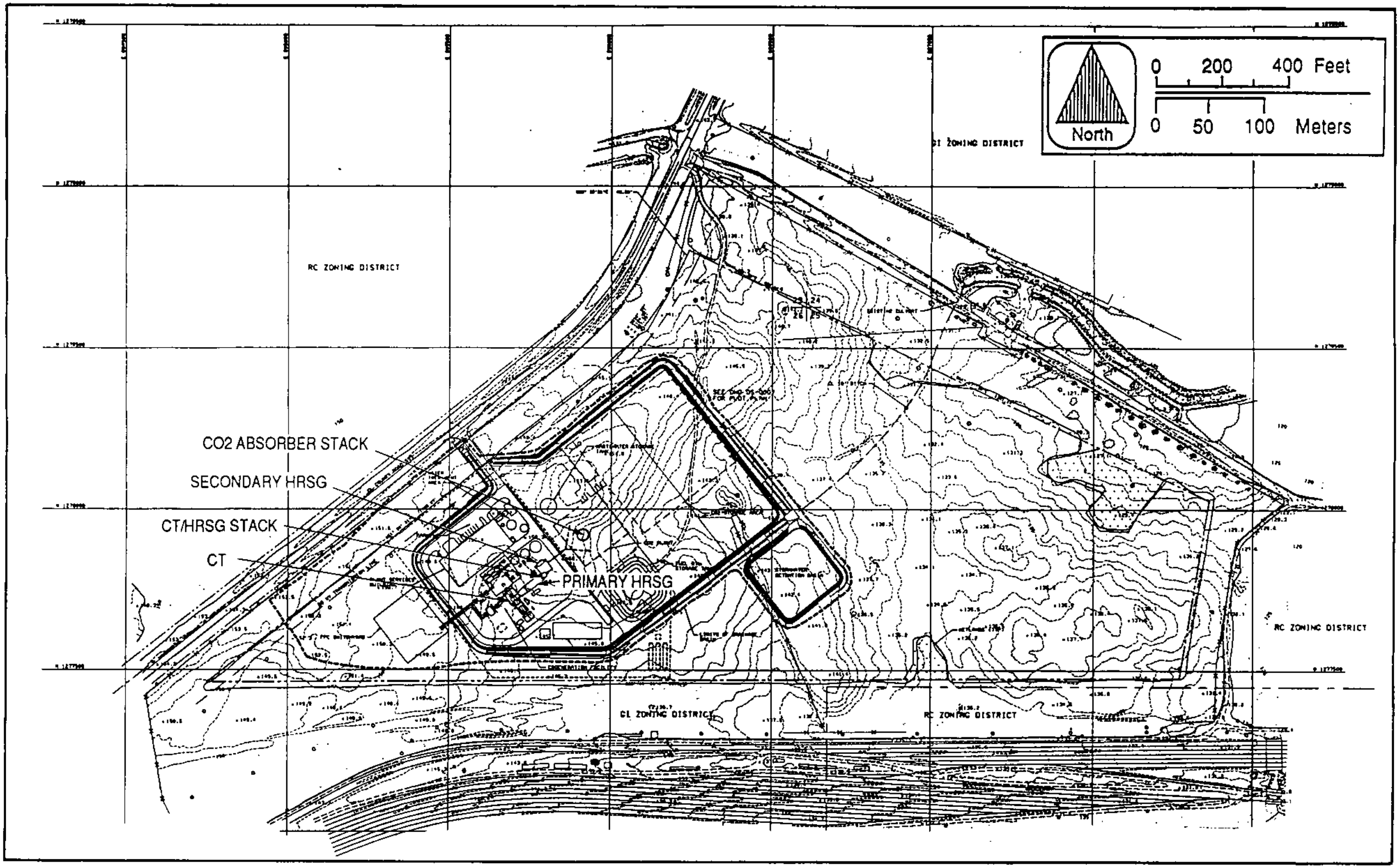


Figure 2-2 PROPOSED SITE ARRANGEMENT
MULBERRY COGEN

SOURCES: C& SW SERVICES, INC., 1/14/92; KBN, 1992.

KBN

2.2 CO_2 PLANT DESCRIPTION

A simplified flow diagram of the CO_2 plant is shown in Figure 2-3. Stack, operating, and emission data for the CO_2 plant are presented in Table 2-2.

A slip stream of cooled gas turbine exhaust (flue gas) from the primary HRSG will feed the CO_2 recovery plant. To enrich the CO_2 content, and simultaneously reduce the O_2 content, the flue gas is first fired in a secondary HRSG with natural gas. The maximum firing rate for the secondary HRSG will be 99 MM Btu/hour.

The enriched flue gas then will feed a pair of CO_2 recovery units. The following description is typical for each of two 75 TPD CO_2 recovery trains. Both units operate simultaneously for a combined output of 150 TPD CO_2.

A flue gas compressor will boost the pressure of the enriched flue gas to about 2.5 pounds per square inch gauge (psig). The gas is then cooled to about 115°F with cooling water which condenses a portion of the contained water vapor. The condensed water is returned to the plant cooling tower basin. The remaining flue gas enters the amine absorber where it is contacted in a countercurrent fashion with a circulating amine solvent. The amine solvent employed is a proprietary solvent (known as FS solvent). The FS solvent is an aqueous monoethanolamine (MEA) solution with proprietary corrosion inhibitors which offer increased oxygen tolerance. The solvent absorbs a majority of the CO_2 contained in the flue gas. The balance of the gas is washed with a circulating water stream to reduce the entrainment of the amine solvent in the treated gas. The treated gas then will exit the top of the absorber, venting to the atmosphere.

The rich amine solvent, loaded with the absorbed CO_2, is pumped to the amine stripper where it is regenerated by steam stripping. The stripping section is generated indirectly by heating the solvent in a steam heated reboiler. The stripping vapors release the absorbed CO_2 which exits overhead in the stripper tower. Low pressure steam is provided for heating

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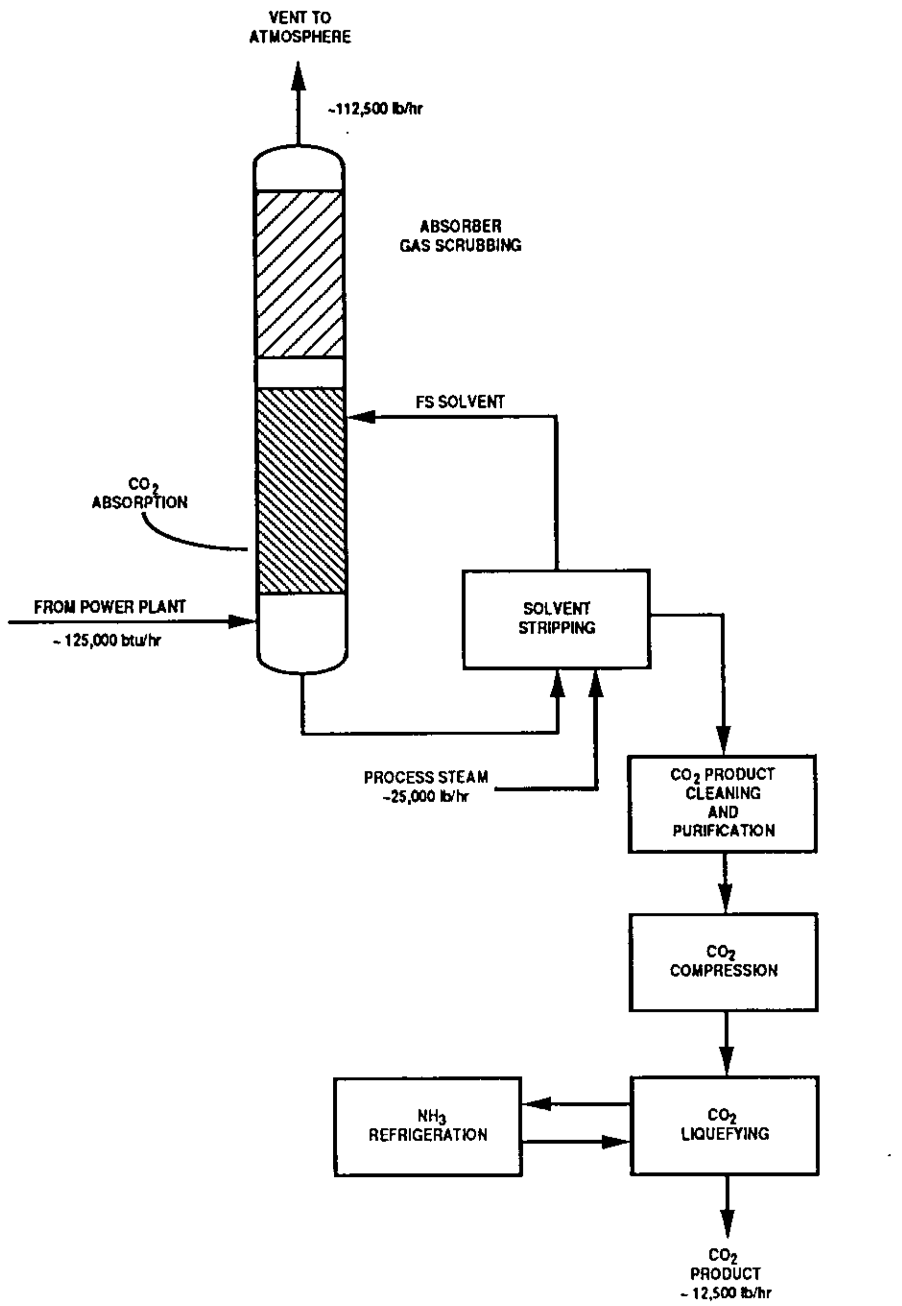

Figure 2-3 SIMPLIFIED FLOW DIAGRAM OF CO2 RECOVERY PLANT

Table 2-2. Stack, Operating, and Emission Data for the Proposed Carbon Dioxide Recovery Plant Emissions and Stack Parameters

	Source			Total Maximum Emissions
	CT[a]	Duct Burner[b]	CO_2 Absorber[c]	
Stack Parameters:				
Height (ft)				170.0
Velocity (ft/sec)				66.5
Temperature (°F)				117.0
Flow (acfm)				28,201.7
Diameter (ft)				3.0
Maximum Hourly Emissions (lb/hr)[d]:				
SO_2	4.87	0.30	0.00	5.17
PM	0.69	0.99	5.00	6.68
NO_x	8.39	15.84	0.00	24.23
CO	3.80	9.90	0.00	13.70
VOC	0.47	2.97	14.73	18.17
Pb	0.0005	Neg.	0.00	0.00
Sulfuric Acid Mist	0.39	0.02	0.00	0.41
F	0.0015	Neg.	0.00	0.0015
Be	0.00012	Neg.	0.00	0.00012
Hg	0.00014	Neg.	0.00	0.00014
As	0.00020	Neg.	0.00	0.00020
Maximum Annual Emissions (TPY)[d]:				
SO_2	20.96	1.30	0.00	22.27
PM	3.31	4.34	21.90	29.54
NO_x	36.15	69.38	0.00	105.53
CO	16.61	43.36	0.00	59.97
VOC	2.03	13.01	64.54	79.58
Pb	0.0018	Neg.	0.00	0.00
Sulfuric Acid Mist	1.69	0.10	0.00	1.79
F	0.0067	Neg.	0.00	0.0067
Be	0.00051	Neg.	0.00	0.00051
Hg	0.00061	Neg.	0.00	0.00061
As	0.00086	Neg.	0.00	0.00086

Note: Neg. = negligible emissions for applicable pollutant.

[a] Based on diverting 120,000 lb/hr of mass flow. Hourly emissions are based on distillate oil firing at 20°F; annual emissions are based on 59°F. Calculated based on the percentage of mass flow to the CO_2 plant.

[b] Based on 99 MM Btu per hour and the following emission factors:
PM = 0.01 lb/MM Btu; SO_2 = 1 grain/100 cf of natural gas;
NO_x = 0.16 lb/MM Btu; CO = 0.1 lb/MM Btu; VOC = 0.03 lb/MM Btu, and H_2SO_4 = 5% of SO_2

[c] VOC emissions based on 6 lb FS solvent/ton of CO_2; VOC as carbon.

[d] Other regulated pollutants are assumed to have negligible or no emissions.

the stripping reboiler. A total of 25,000 lb/hr of steam is used to generate the CO_2 production of 150 TPD.

A solvent reclaimer is operated intermittently to reduce degradation products and heat stable salts in the circulating amine solution which result from side reactions and thermal/chemical degradation of the solvent. The reclaimed solution is vaporized by indirect steam heating and returned to the stripper. The balance of the reclaimer "bottoms" represents a liquid waste product for disposal off-site.

The regenerated amine solvent from the stripper is cooled, filtered, and pumped back to the absorber.

The water saturated CO_2 stream exiting the stripper overhead is cooled with condensed water returned to the stripper as reflux. The remaining CO_2 vapor stream proceeds to the CO_2 purification and liquefaction section.

The CO_2 vapor is first contacted with a recirculating potassium permanganate solution for removal of amine solvent traces as well as any trace levels of NO_x and SO_2. The gas is then water washed with a recirculating water stream and feeds an activated carbon tower for final purification. The scrubbing operation produces a small aqueous permanganate stream for disposal off-site. The water wash operation produces a water effluent which is sent to wastewater storage for zero discharge treating.

The purified CO_2 vapor is then compressed from near atmospheric pressure to about 250 psig. The compressor discharge is cooled with cooling water which condenses a portion of the contained water vapor. This water is recycled back to the amine unit. The CO_2 vapor is then dried in a CO_2 dryer to prevent subsequent freezing of the remaining water vapor.

The dry CO_2 is then liquified by condensing with a closed loop ammonia refrigeration system. Liquid CO_2 of beverage and food grade quality is then pressured to intermediate storage before being trucked from the site.

Dry ice will be produced on-site. A portion of the liquid CO_2 produced will be converted to solid and gaseous CO_2. Of the portion of liquid CO_2 used in dry ice production, about 40 percent is converted to solid CO_2, 40 percent is reliquefied, and 20 percent is lost as a gas.

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 facility (combined cycle turbine and CO_2 processing plant) can begin operation.

3.1 NATIONAL AND STATE AAQS

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

3.2 PSD REQUIREMENTS

3.2.1 GENERAL REQUIREMENTS

Under federal and State of Florida PSD review requirements, all major new or modified sources of air pollutants regulated under the Clean Air Act (CAA) must be reviewed and a preconstruction permit issued. Florida's State Implementation Plan (SIP), which contains PSD regulations, has been approved by EPA, and therefore PSD approval authority has been granted to the 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 ($\mu g/m^3$)

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

[a] Short-term maximum concentrations are not to be exceeded more than once per year.
[b] Maximum concentrations are not to be exceeded.
[c] Proposed October 5, 1989.
[d] Achieved when the expected number of days per year with concentrations above the standard is fewer than 1.

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

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

Sources: 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_2 and total suspended particulate matter [PM(TSP)] concentrations would constitute significant deterioration. The magnitude of the allowable increment depends on the classification of the area in which a new source (or modification) will be located or have an impact. Three classifications were designated, based on criteria established in the CAA Amendments. Initially, Congress promulgated areas as Class I (international parks,

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

Pollutant	Regulated Under	Significant Emission Rate (TPY)	De Minimis Monitoring Concentration[a] (μg/m³)
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[b]
Lead	NAAQS	0.6	0.1, 3-month
Sulfuric Acid Mist	NSPS	7	NM
Total Fluorides	NSPS	3	0.25, 24-hour
Total Reduced Sulfur	NSPS	10	10, 1-hour
Reduced Sulfur Compounds	NSPS	10	10, 1-hour
Hydrogen Sulfide	NSPS	10	0.2, 1-hour
Asbestos	NESHAP	0.007	NM
Beryllium	NESHAP	0.0004	0.001, 24-hour
Mercury	NESHAP	0.1	0.25, 24-hour
Vinyl Chloride	NESHAP	1	15, 24-hour
Benzene	NESHAP	[c]	NM
Radionuclides	NESHAP	[c]	NM
Inorganic Arsenic	NESHAP	[c]	NM

[a] Short-term concentrations are not be be exceeded.

[b] No de minimis concentration; an increase in VOC emissions of 100 TPY or more will require monitoring analysis for ozone.

[c] Any emission rate of these pollutants.

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

NAAQS = National Ambient Air Quality Standards.
NM = No ambient measurement method.
NSPS = New Source Performance Standards.
NESHAP = National Emission Standards for Hazardous Air Pollutants.
μg/m³ = 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 NO_x and established PSD increments for NO_2 concentrations. The EPA class designations and allowable PSD increments are presented in Table 3-1. FDER has adopted the EPA class designations and allowable PSD increments for SO_2, PM(TSP), and NO_2 increments.

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

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

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

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

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

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

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

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

3.2.3 CONTROL TECHNOLOGY REVIEW

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

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

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

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

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

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

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

3.2.4 AIR QUALITY MONITORING REQUIREMENTS

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

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

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

3.2.5 SOURCE IMPACT ANALYSIS

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

EPA has recently recommended significant impact levels for PSD Class I areas. The levels are as follows:

Pollutant	Averaging Time	Maximum Significance Level ($\mu g/m^3$)
SO_2	3-hour	1.23
	24-hour	0.275
	Annual	0.1
PM(TSP)	24-hour	1.35
	Annual	0.27
NO_2	Annual	0.1

Although these levels were proposed for use in Virginia and may not be binding in other states, the proposed levels serve as a guideline in assessing a source's impact in a Class I area. EPA's Office of Air Quality Planning and Standards has initiated a motion that will lead to rulemaking to address the general need for Class I significant impact levels. The action is part of EPA's efforts to incorporate new source review provisions of the 1990 Clean Air Act Amendments. Because the process of developing the regulations will be lengthy, EPA believes that immediate guidance concerning the significant impact levels is appropriate in order to assist states in implementing the PSD permit process.

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:

$$Hg = H + 1.5L$$

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

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

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

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

3.3 NONATTAINMENT RULES

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

For major facilities or major modifications that locate in an attainment or unclassifiable area, the nonattainment review procedures apply if the source or modification is located within the area of influence of a nonattainment area. The area of influence is defined as an area that is outside the boundary of a nonattainment area but within the locus of all points that are 50 km outside the boundary of the nonattainment area. Based on Chapter 17-2.510(2)(a)2.a, F.A.C., all 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 Polk County, which has been designated by EPA and FDER as an attainment area for all criteria pollutants. Polk County and surrounding counties are designated as PSD Class II areas for SO_2, PM(TSP), and NO_x. The site is located approximately 120 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 SO_2, PM(TSP), PM(PM10), NO_2, CO, VOCs, sulfuric acid mist, Be, 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 SO_2, PM(TSP), PM(PM10), NO_2, CO, VOCs, sulfuric acid mist, Be, 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 except SO_2. For VOCs, the maximum emissions from the proposed facility exceeds the de minimis emission rate of 100 TPY. There are no acceptable ambient monitoring methods for sulfuric acid mist, radionuclides, or As; therefore, monitoring is not required for these pollutants.

For SO_2 and ozone concentrations, the monitoring data collected in Polk County are proposed for use in satisfying the preconstruction monitoring requirements (see Section 5.2).

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 stacks for the proposed turbine and CO_2 plant will be 125 feet (ft) (38.1 m) and 170 ft (51.8 m), respectively. These stack heights do not

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

Pollutant	Emissions (TPY) Potential Emissions From Proposed Facility	Significant Emission Rate	PSD Review
Sulfur Dioxide	418*	40	Yes
Particulate Matter (TSP)	92	25	Yes
Particulate Matter (PM10)	92	15	Yes
Nitrogen Dioxide	788	40	Yes
Carbon Monoxide	373	100	Yes
Volatile Organic Compounds	118	40	Yes
Lead	0.036	0.6	No
Sulfuric Acid Mist	34	7	Yes
Total Fluorides	0.13	3	No
Total Reduced Sulfur	NEG	10	No
Reduced Sulfur Compounds	NEG	10	No
Hydrogen Sulfide	NEG	10	No
Asbestos	NEG	0.007	No
Beryllium	0.010	0.0004	Yes
Mercury	0.012	0.1	No
Vinyl Chloride	NEG	1	No
Benzene	NEG	0	No
Radionuclides	NEG	0	No
Inorganic Arsenic	0.017	0	Yes

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

*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 Proposed Mulberry Cogeneration Facility Compared to PSD De Minimis Monitoring Concentrations

Pollutant	Concentration ($\mu g/m^3$) Predicted Net Increase in Impacts	Concentration ($\mu g/m^3$) De Minimis Monitoring Concentration
Sulfur Dioxide	15.5	13, 24-hour
Particulate Matter (TSP)	2.8	10, 24-hour
Particulate Matter (PM10)	2.8	10, 24-hour
Nitrogen Dioxide	0.85	14, annual
Carbon Monoxide	23.6	575, 8-hour
Volatile Organic Compounds	118 TPY	100 TPY[a]
Sulfuric Acid Mist	NA	NM
Beryllium	0.0004	0.001, 24-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.

[a] No de minimis concentration; an increase in emissions of 100 TPY or more will require a monitoring analysis for ozone.

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 Polk 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. The NTLs for pollutants applicable to the proposed project are presented in Table 3-5. Emissions for these pollutants are presented in Appendix A.

Table 3-5. Summary of Florida No Threat Levels for Toxic Air Pollutants Applicable to the Proposed Facility Analysis

Pollutant	No Threat Level (μg/m) 8-Hour	24-Hour	Annual
Antimony	5	1.2	0.3
Arsenic	2	0.48	0.00023
Barium	5	1.2	50
Beryllium	0.02	0.0048	0.00042
Cadmium	0.5	0.12	0.00056
Chlorine	15	3.6	NE
Chromium	5	1.2	1000
Colbalt	0.5	0.12	NE
Copper	1	0.24	NE
Ethanolamine	80	19.2	NE
Fluorine	2	0.48	50
Formaldehyde	4.5	1.08	0.077
Lead	1.5	0.36	0.09
Manganese	50	12	NE
Mercury	0.5	0.12	0.3
Nickel	0.5	0.12	0.0042
Polyorganic Matter	NE	NE	NE
Selenium	2	0.48	NE
Sulfuric Acid Mist	10	2.38	NE
Vanadium	0.5	0.12	20
Zinc[a]	50	12	NE

Note: NE = none established.

[a] As zinc oxide.

4.0 CONTROL TECHNOLOGY REVIEW

4.1 APPLICABILITY

The control technology review requirements of the PSD regulations are applicable to emissions of PM10, SO_2, NO_x, CO, VOC, H_2SO_4 mist, Be, 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 x 10^6 Btu/hr [40 CFR 60.332 (b)];
2. Stationary gas turbines with a heat input at peak load between 10 and 100 x 10^6 Btu/hr [40 CFR 60.332 (c)]; or
3. Stationary gas turbines with a manufacturer's rate base load at ISO conditions of 30 MW or less [40 CFR 60.332 (d)].

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

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

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

Pollutant	Emission Limitation[a]
Nitrogen Oxides[b]	0.0075 percent by volume (75 ppm) at 15 percent O_2 on a dry basis adjusted for heat rate and fuel nitrogen

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

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

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

where:

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

Source: 40 CFR 60 Subpart GG.

For the proposed CTs, the NSPS emission limit would be 93 ppm on oil and 96 ppm on gas (corrected to 15 percent oxygen at a fuel-bound nitrogen content of 0.015 percent). The applicable NSPS for the secondary duct burner will be 40 CFR 60, Subpart Dc. 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_x Control Technologies

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

Table 4-3 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_x controls for CTs established as LAER/BACT by state agencies are selective catalytic reduction (SCR) with wet injection and wet injection alone. When SCR has been employed, wet injection is used initially to reduce NO_x emissions. SCR has been installed or permitted in about 132 projects. The majority of these projects (more than 90 percent) are cogeneration facilities with capacities of 50 MW or less. About

Table 4-2

Summary of NSPS For Small Industrial-Commercial-Institutional Steam Generating Units

Unit Size (heat input)	Fuel	Annual Capacity Factor	Emission Standard
		PARTICULATE MATTER	
30-100 MMBtu/hr	Coal; Coal w/other fuels	>90% on coal	0.05 lb/MMBtu
		<90% on coal	0.10 lb/MMBtu
	Wood; Wood w/other fuels (except coal)	>30% on wood	0.10 lb/MMBtu
		<30% on wood	0.30 lb/MMBtu
	Oil	No limitation	No emission limit
		OPACITY	
30-100 MMBtu/hr	All fuels	No limitation	20% opacity
		SULFUR DIOXIDE	
>75 MMBtu/hr	Coal	>55% on coal	1.2 lb/MMBtu; 90% reduction
	Coal	<55% on coal	1.2 lb/MMBtu
	Coal w/emerging SO2 control technology	>55% on coal	0.6 lb/MMBtu; 50% reduction
	Coal in duct burner of combined cycle system	No limitation	1.2 lb/MMBtu
	Oil	No limitation	0.5 lb/MMBtu or 0.5% S fuel
	Coal refuse in fluidized bed combustor	No limitation	1.2 lb/MMBtu; 80% reduction
30-75 MMBtu/hr	Coal	No limitation	1.2 lb/MMBtu
	Coal w/emerging SO2 control technology	No limitation	0.6 lb/MMBtu
	Coal in duct burner of combined cycle system	No limitation	0.6 lb/MMBtu
	Oil	No limitation	0.5 lb/MMBtu or 0.5% S fuel
	Coal refuse in fluidized bed combustor	No limitation	1.2 lb/MMBtu

Source: 40 CFR Part 60 Subpart Dc

SUBDCREG
10/23/90

Table 4-3. Summary of BACT Determinations for NOx from Gas-fired Turbines

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NOx Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	pmvd	basis)	Control Method	Eff. (%)
Lake Cogen	FL	Nov-91	Combined Cycle	120 MW	—	—	—	25	@ 15% O2	Steam Injection	—
Pasco Cogen	FL	Nov-91	Combined Cycle	120 MW	—	—	—	25	@ 15% O2	Steam Injection	—
Florida Power Corporation	FL	Sep-91	Simple Cycle	552 MW	—	—	—	42	@ 15% O2	Dry Low NOx Combustor	—
Enron Louisana Energy Co	LA	Aug-91	Gas Turbines (2)	78.2 MMBtu/hr	—	6.3	—	40	ppmv @ 15% O2	Water Inject 0.67 lb/lb	71.00%
City of Lakeland	FL	Jul-91	Combined Cycle	120 MW	—	—	—	25	@ 15% O2	Dry Low NOx Combustor	—
Sumas Energy, Inc.	WA	Jun-91	Gas Turbine	80 MW	—	—	—	6	@ 15% O2	SCR	90.00%
Florida P&L Co. (Martin)	FL	Jun-91	Combined Cycle	860 MW	—	—	—	25	@ 15% O2	Dry Low NOx Combustor	—
Commonwealth Atlantic LTD Partn.	VA	Mar-91	Gas Turbine	1533 MMBtu/hr	—	139	—	25	ppmvd	H2o Injection & Low NOx Comb.	—
Commonwealth Atlantic LTD Partn.	VA	Mar-91	Gas Turbine	1400 MMBtu/hr	—	—	1032	42	ppmvd	Water Injection	—
Florida P&L Co. (Ft. Lauderdale)	FL	Mar-91	Combined Cycle	860 MW	—	—	—	42	@ 15% O2	Steam Injection	—
Hardee Power Station	FL	Dec-90	Combined Cycle	660 MW	—	—	—	42	@ 15% O2	Wet Injection	—
Salinas River Cogen	CA	Nov-90	Gas Turbine	43.2 MW	—	10	—	6	@ 15% O2	Dry Low NOx Comb. & SCR	—
Sargent Canyon Cogen Co	CA	Nov-90	Gas Turbine	42.5 MW	—	10	—	6	@ 15% O2	Dry Low NOx Comb. & SCR	—
March Point Cogen	WA	Oct-90	Turbine	80 MW	—	—	—	25	@ 15% O2	Massive Steam Injection	80.00%
Las Vegas Cogen	NV	Oct-90	Turbine, Peaking	397 MMBtu/hr	—	—	—	10	ppm	Water Injection & SCR	—
Delmarva Power Corporation	DE	Sep-90	Combined Cycle	450 MW	0.10	—	—	25	@ 15% O2	Dry Low NOx Combustor	—
Doswell Limited Partnership	VA	May-90	Turbine	1,261 MMBtu/hr	—	—	—	9	ppmvd	Dry Comb. to 25 ppm, SCR to 9 pp	—
Fulton Cogeneration Assoc.	NY	Jan-90	GE LM5000	500 MMBtu/hr	—	—	—	36		Water Injection	—
O'Brian California Cogen II	CA	Jan-90	Gas Turbine	49.50 MW	—	114.6	—	—		SCR	—
Arrowhead Cogeneration	VT	Dec-89	Gas Turbine	282.0 MMBtu/hr	—	—	—	9	@ 15% O2, 1H Av	Water Injection & SCR	80.00%
Richmond Power Enterprise Partn.	VA	Dec-89	Gas Turbine	1,163.5 MMBtu/hr	—	—	—	8.2	@ 15% O2	Steam Inj. & SCR	—
JMC Selkirk, Inc.	NY	Nov-89	GE Frame 7	80 MW	—	—	—	25	ppm	Steam Injection	—
Badger Creek Limited	CA	Oct-89	GT-Cogen	457.8 MMBtu/hr	0.0135	—	—	—		Steam Injection & SCR	—
Capitol District NRG Ctr	CT	Oct-89	Gas Turbine	738.8 MMBtu/hr	—	—	—	42	@ 15% O2	Steam Injection	—
City of Anaheim GT Proj.	CA	Sep-89	Gas Turbine	442 MMBtu/hr	—	3.75	—	—		Steam Injection & SCR	69.60%
Panda-Rosemary Corp.	NC	Sep-89	GE Frame 6	499 MMBtu/hr	0.17	83	—	—		Water Injection	—
Kamine Syracuse Cogen	NY	Sep-89	Turbine	79 MW	—	—	—	36	ppm	Water Injection	—
Cimarron Chemical Co.	CO	Aug-89	Turbines (2)	271.0 MMBtu/hr	—	—	—	65	ppmv @ 15% O2	Steam Injection	—
Tropicana Products, Inc.	FL	May-89	Gas Turbine	45.40 MW	—	—	—	42	@ 15% O2	Steam Injection	—
Empire Energy - Niagara Cogen	NY	May-89	GE Frame 6 (3)	1,248 MMBtu/hr	—	—	—	42	ppm	Steam Injection	—
Megan-Racine Assoc.	NY	Mar-89	GE LM 5000	430 MMBtu/hr	—	—	—	42	ppm	Water Injection	—
Potomac Electric Power Company	MD	Mar-89	Combined Cycle	860 MW	—	—	—	42	@ 15% O2	Steam Injection	—
Indec/Oswego Hill Cogen	NY	Feb-89	GE Frame 6	40 MW	—	—	—	42	@ 15% O2	Water Injection	—

Table 4-3. Summary of BACT Determinations for NOx from Gas-fired Turbines

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NOx Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	pmvd	basis)	Control Method	Eff. (%)
Pawtucket Power	RI	Jan-89	Turbine	58 MW	—	—	—	9	@ 15% O2	SCR	—
L&J Energy System Cogen	NY	Jan-89	GE LM 5000	40 MW	—	—	—	42	ppm	Steam Injection	—
Mojave Cogen	CA	Jan-89	Turbine	490 MMBtu/hr	0.031	—	—	—		—	—
Ocean State Power	RI	Jan-89	Combine Cycle	500 MW	—	—	—	9	@ 15% O2	Water Injection & SCR	—
Mojave Cogen	CA	Dec-88	Turbine	45 MW	—	—	—	10	ppm	Steam Injection & SCR	—
Champion International	AL	Nov-88	Gas Turbine	35 MW	—	—	—	42	@ 15% O2	Steam Injection	70.00%
Indeck-Yerks Energy Services	NY	Nov-88	GE Frame 6	40 MW	—	—	—	42	@ 15% O2	Steam Injection	—
Long Island Lighting Co	NY	Nov-88	Peaking Units (3)	75 MW	—	—	—	55	ppm	Water Injection	—
Amtrak	PA	Oct-88	Turbine (2)	20 MW	—	—	—	42	@ 15% O2	H2O Injection	—
Mobile Oil	CA	Sep-88	Turbine (2)	81.40 MMBtu/hr	0.047	3.78	—	—		Water Inj. & SCR	—
Kamine South Glens Falls	NY	Sep-88	GE Frame 6	40 MW	—	—	—	42	ppm	Steam Injection	—
Orlando Utilities	FL	Sep-88	Gas Turbine (2)	35 MW	—	—	—	42	@ 15% O2	Steam Injection	—
Delmarva Power Corporation	DE	Aug-88	Turbine (2)	200 MW	—	—	—	42	ppm	Low NOx Burners & Water Inj.	—
O'Brien Cogen	CT	Aug-88	Gas Turbine (2)	499.9 MMBtu/hr	—	—	—	39	@ 15% O2	Water Injection	—
Kamine Carthage	NY	Jul-88	GE Frame 6	40 MW	—	—	—	42	ppm	Steam Injection	—
ADA Cogeneration	MI	Jun-88	Turbine	245.0 MMBtu/hr	—	—	—	42	@ 15% O2, 1H Av	H20 Injection	59.00%
CCF-1 Jefferson Station	CT	May-88	Gas Turbines (2)	110 MMBtu/hr	—	—	—	36	@ 15% O2	Water Injection	—
Merck Sharp & Pohme	PA	May-88	Turbine	310 MMBTU/hr	—	—	—	42	@ 15% O2	Steam Injection	—
Virginia Power	VA	Apr-88	GE Turbine	1,875 MMBTU/hr	—	490		42	@ 15% O2	Steam Injection	—
TBG/Grumman	NY	Mar-88	Gas Turbine	16 MW	0.2	—	—	75	ppm	H2O Inj. & Combustion Controls	—
Combined Energy Resources	CA	Feb-88	Gas Turbine	25.94 MW	—	199.0	—	—		H2O Injection & SCR	81.00%
Texas Gas Transmission Corp.	KY	Feb-88	Gas Turbine	14300 HP	—	—	—	—		NOx 0.015 % by Volume	—
Midland Cogeneration Venture	MI	Feb-88	Turbines (12)	984.2 MMBTU/hr	—	—	—	42	@ 15% O2	Steam Injection	—
Midway-Sunset Cogen	CA	Jan-88	GE Frame 7 (3)	75 MW	—	85	—	—		Water Inj. & Quiet Combustion	—
Downtown Cogeneration Assoc.	LA	Aug-87	Gas Turbine	71.9 MMBtu/hr	—	—	—	42	ppmvd @ 15% O2	Water Injection	—
BAF Energy	CA	Jul-87	Turbine, Generator	887.2 MMBTU/hr	—	30.1	—	9	ppm @ 15% O2	Steam Injection & SCR	80.00%
AES Placerita, Inc.	CA	Jul-87	Turbine	530 MMBTU/hr	—	14.2	—	9	@ 15% O2	St./F Ratio 2.2:1 & SCR	—
AES Placerita, Inc.	CA	Jul-87	Gas Turbine	530 MMBTU/hr	—	12.0	—	9	@ 15% O2	St./F Ratio 2.2:1 & SCR	—
Power Development Co.	CA	Jun-87	Gas Turbine	49 MMBTU/H	—	1.5	—	9	@ 15% O2	H2O Injection & SCR	—
San Joaquin Cogen Limited	CA	Jun-87	Gas Turbine	48.6 MW	—	10.4	—	6	@ 15% O2	H2O Injection & SCR	76.00%
Cogen Technologies	NJ	Jun-87	GE Frame 6 (3)	40 MW	—	—	—	9.6	@ 15% O2	H2O Injection & SCR	95.00%
Trunkline LNG	LA	May-87	Gas Turbine	147,102 SCF/hr	—	59		—		—	—

Table 4-3. Summary of BACT Determinations for NOx from Gas-fired Turbines

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	NOx Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	pmvd	basis)	Control Method	Eff. (%)
Pacific Gas Transmission	OR	May-87	Gas Turbine	14,000 HP	—	50.3	—	154		Combustion Control	—
Anheuser-Busch	FL	Apr-87	Gas Turbine	95.7 MMBTU/hr	0.10	—	—	—		—	—
Alaska Elect. Gen. & Trans.	AK	Mar-87	Gas Turbine	80 MW	—	—	—	75	@ 15% O2	H2O Injection	—
Sycamore Cogen	CA	Mar-87	Gas Turbine	75 MW	—	—	—	—		—	—
U.S. Borax & Chemical Corp.	CA	Feb-87	Gas Turbine	45 MW	—	40	—	25	ppm @ 15% O2	Proper Combust. Techniques	—
Sierra LTD.	CA	Feb-87	GE Gas Turbine	11.34 MMCF/D	0.016	4.04	—	—		Steam Injection & SCR	95.86%
Midway-Sunset Project	CA	Jan-87	Gas Turbines (3)	973 MMBTU/hr	—	113.4	—	16.31	ppmv	H2O Injection	73.00%
City of Santa Clara	CA	Jan-87	Gas Turbine	—	—	—	—	42	@ 15% O2	Water Injection	—
O'Brien NRG Systems/Merchants Re	CA	Dec-86	Gas Turbine	359.5 MMBtu/hr	—	30.3	—	15	@ 15% O2	Water Injection & SCR	—
California Dept. of Corr.	CA	Dec-86	Gas Turbine	5.1 MW	—	—	—	38	@ 15% O2	1:1 H2O Injection	—
Double 'C' Limited	CA	Nov-86	Gas Turbine	25 MW	—	8.08	—	—		H2O Inj. & Selected Catalytic Red.	—
Kern Front Limited	CA	Nov-86	Gas Turbine (2)	50 MW	—	8.08	—	4.5	@ 15% O2	Water Injection & SCR	95.80%
PG&E, Station T	CA	Aug-86	GE LM5000	396 MMBTU/hr	—	63	—	25	ppm @ 15% O2	Steam Injection @ St/F Ratio of 1.7/	75.00%
Wichita Falls E. I., I.	TX	Jun-86	Gas Turbine	20 MW	—	—	684	—		Steam Injection	—
Formosa Plastic Corp.	TX	May-86	GE MS 6001	38.4 MW	—	—	640	—		Steam Injection	—
Kern Energy Corp.	CA	Apr-86	Gas Turbine	8.8 MMCF/D	0.023	8.29	—	—		Steam Inj., Low NOx Config. & SC	87.00%
Monarch Cogen	CA	Apr-86	Combined Cycle	92.20 MMBtu/hr	—	8.02	—	22	@ 15% O2	SCR	—
Moran Power, Inc.	CA	Apr-86	Gas Turbine	8.0 MMCF/D	0.02	8.29	—	—		Steam Inj., Low NOx Config. & SC	87.00%
Southeast Energy, Inc.	CA	Apr-86	Gas Turbine	8.0 MMCF/D	0.023	8.29	—	—		Steam Inj., Low NOx Config. & SC	87.00%
Western Power System, Inc	CA	Mar-86	GE Gas Turbine	26.5 MW	—	—	—	9	@ 15% O2	H2O Injection & SCR	80.00%
AES Placerita, Inc.	CA	Mar-86	Turbine	519 MMBTU/hr	—	26.2	—	7	@ 15% O2	H2O Injection & SCR	—
OLS Energy	CA	Jan-86	GE Gas Turbine	256 MMBTU/hr	—	—	—	9	@ 15% O2	H2O Injection & Scrubber	80.00%
Union Cogeneration	CA	Jan-86	Gas Turbine	16 MW	—	—	—	25	@ 15% O2	H2O Injection & Scrubber	—

83 percent (i.e., 109) of the projects have been in California. Of these 109 projects that have either installed SCR or have been permitted with SCR, 43 percent have been in the Southern California NO_2 nonattainment 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 or less per CT.

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

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

In Florida, a majority of the most recent PSD permits and BACT determinations for gas turbines have required either wet injection or dry low-NO_x technology for NO_x control. The emission limits included in these permits and BACT determinations are 25 ppm (corrected to 15 percent O_2, dry conditions) for natural-gas firing.

4.3.1.2 Technology Description and Feasibility

Selective Catalytic Reduction (SCR)--SCR uses ammonia (NH_3) to react with NO_x in the gas stream in the presence of a catalyst. NH_3, which is diluted with air to about 5 percent by volume, is introduced into the gas stream at reaction temperatures between 600°F and 750°F. The reactions are as follows:

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

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

SCR operating experience, as applied to gas turbines, consists primarily of baseload natural-gas-fired installations either of cogeneration or combined cycle configuration; no simple cycle facilities have SCR. Exhaust gas temperatures of simple cycle CTs 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 NH_3 and NO_x on the catalyst surface.

The use of SCR has been limited to facilities that burn natural gas or small amounts of fuel oil since SCR catalysts are contaminated by sulfur-containing fuels (i.e., fuel oil). For most fuel-oil-burning facilities, catalyst operation is discontinued, or the exhaust bypasses the SCR system. While the operating experience has not been extensive, certain cost, technical, and environmental considerations have surfaced. These considerations are summarized in Table 4-4.

As presented in Table 4-4, ammonium salts (ammonium sulfate and bisulfate) are formed by the reaction of 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. While the formation of ammonium salts is primarily associated with oil firing, sulfur combustion products from natural gas also could form small amounts of ammonium salts.

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

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 NH_3 to NO_x generally needed to obtain high removal efficiencies. Special storage and handling equipment required.
Space Requirements	For new installations, space in the catalyst is needed for replacement layers. Additional space is also required for catalyst maintenance and replacement.
Backup Equipment	Reliability requirements necessitate redundant systems, such as ammonia control and vaporization equipment.
Catalyst Back Pressure Heat Rate Reduction	Addition of catalyst creates backpressure on theturbine, which reduces overall heat rate.
Electrical	Additional usage of energy to operate ammonia pumps and dilution fans.
TECHNICAL:	
Ammonia Flow Distribution	NH_3 must be uniformly distributed in the exhaust stream to assure optimum mixing with NO_x before 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.

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

Consideration	Description
Ammonia Control	Quantity of NH_3 introduced must be carefully controlled. With too little NH_3, the desired control efficiency is not reached; with too much NH_3, NH_3 emissions (referred to as slip) occur.
Flow Control	The velocity through the catalyst must be within a range to assure satisfactory residence time.
ENVIRONMENTAL:	
Ammonia Slip	NH_3 slip (NH_3 that passes unreacted through the catalyst and into the atmosphere) can occur if 1) too much ammonia is added, 2) the flow distribution is not uniform, 3) the velocity is not within the optimum range, or 4) the proper temperature is not maintained.
Ammonium Salts	Ammonium salts (ammonium sulfate and bisulfate) can lead to increased corrosion. These salts can occur when firing natural gas. These compounds are emitted as particulates.
Ammonia Transportation and Storage	Storage and handling of anhydrous ammonia produces additional environmental risks. Appropriate controls and contingency plans in the event of a release is required.

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_x emissions. The amount of NO_x reduction possible depends on the combustor design and the water-to-fuel ratio employed. An increase in the water-to-fuel ratio will cause a concomitant decrease in NO_x emissions until flame instability occurs. At this point, operation of the CT becomes inefficient and unreliable, and significant increases in products of incomplete combustion will occur (i.e., CO and VOC emissions).

For oil or propane firing, water injection will be used. The NO_x emission level guaranteed by GE is 42 ppmvd corrected to 15 percent oxygen.

Dry Low-NO_x Combustor--In the past several years, CT manufacturers have offered and installed machines with dry low-NO_x combustors. These combustors, which are offered on machines manufactured by GE, Kraftwork Union, and ABB, can achieve NO_x concentrations of 25 ppmvd or less when firing natural gas. Thermal NO_x formation is inhibited by using combustion techniques where the natural gas and combustion air are premixed before ignition. For the CT being considered for the project, the combustion chamber design includes the use of dry low-NO_x combustor technology. The NO_x emission level guaranteed by GE for the project is 25 ppmvd (corrected to 15 percent O_2) when firing natural gas.

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

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

The amount of urea required is most cost-effective when the treatment rate is 0.5 to 2 moles of urea per mole of NO_x. In addition to the original EPRI urea patents, Fuel Tech claims to have a number of proprietary catalysts capable of expanding the effective temperature range of the reaction to between 1,600°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. Sulfur trioxide (SO_3), if present, will react with ammonia created from the urea to form ammonium bisulfate, potentially plugging the cold end equipment downstream.

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

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

The NO_xOUT system has not been demonstrated on any combustion turbine/HRSG unit.

The NO_xOUT process is not technically feasible for the proposed project because of the high application temperature of 1,600°F to 1,950°F. The maximum exhaust gas temperature of the CT is about 1,000°F. Raising the exhaust temperature the required amount essentially would require installation of a heater. This would be economically prohibitive and would result in an increase in fuel consumption, an increase in the volume of gases that must be treated by the control system, and an increase in uncontrolled air emissions, including NO_x.

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

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

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

<u>Nonselective Catalytic Reduction</u>--Certain manufacturers, such as Engelhard, market a nonselective catalytic reduction system (NSCR) for NO_x control on reciprocating engines. The NSCR process requires a low oxygen content in the exhaust gas stream and high temperature (700°F to 1,400°F) in order to be effective. CTs have the required temperature but also 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_x control device for CTs.

<u>Control Technologies for Duct Firing</u>--The proposed control technology for duct firing in the secondary HRSG will be the use of combustion controls that will limit the emissions to 0.16 $lb/10^6$ Btu heat input.

The applicable NSPS for the secondary HRSG is the recently promulgated standards for small industrial-commercial-institutional steam generating units contained in 40 CFR Part 60 Subpart Dc. There are no NO_x emission limits applicable to these sizes of sources (i.e., less than 100 million Btu per hour heat input). The NSPS for larger steam generators (i.e., greater than 100 million Btu per hour heat input) is found in 40 CFR Part 60 Subpart Db. The NO_x emission limit for natural gas firing is 0.2 lb NO_x per million Btu heat input. BACT emission limits for duct burners located in primary HRSGs associated with combined cycle power plants are typically 0.1 lb NO_x per million Btu heat input.

The secondary HRSG associated with this project is quite different in terms of heat release and purpose than those normally associated with combined cycle plants. In typical combined cycle plants, the purpose of the secondary HRSG is to enhance steam production. While the secondary HRSG proposed in this project will provide additional steam, it will enhance the source gas being provided to the CO_2 recovery plant. This step is necessary to reduce oxygen content to provide proper gas composition for CO_2 absorption.

The heat released relative to the volume of air flow is significantly greater for the proposed source than other combined cycle facilities. For this project, the heat released will be approximately 3,000 Btu per cfm, while the highest heat release from a recently permitted project in Florida (i.e., Pasco and Lake Cogen Limited) was approximately 700 Btu per cfm.

NO_x is related to heat release; therefore, a higher NO_x emission limit is requested for the proposed project.

Summary of Technically Feasible NO_x Control Methods--The available information suggests that SCR with dry low-NO_x combustor technology or with wet injection would produce the lowest NO_x emissions and is technically feasible. Dry low-NO_x combustion alone has increasingly been approved by regulatory agencies as BACT and is a technically feasible alternative for the project.

A technical evaluation of other tail gas controls (i.e., NO_xOUT, Thermal DeNO_x, and NSCR) indicates that these processes have not been applied to CT/HRSG and are technically infeasible for the project because of process constraints (e.g., temperature).

For the BACT analysis, SCR with dry low-NO_x combustion is capable of achieving a NO_x emission level of 9 ppm when firing natural gas (corrected to 15 percent O_2 dry conditions) and dry low-NO_x combustion alone can achieve 25 ppm (corrected). When firing oil or propane, the emissions with SCR and wet injection would be about 15 ppm (corrected), whereas emissions with water injection alone would be 42 ppm (corrected).

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 dry low-NO_x combustion at an emission rate of approximately 9 ppmvd corrected to 15 percent O_2 when firing gas and 15 ppmvd when firing oil or propane; and

2. Dry low-NO_x combustion at an emission rate of 25 ppmvd corrected to 15 percent O_2 when firing gas and 42 ppmvd (corrected) when firing oil or propane;

As discussed in Section 2.1, the CT will be fired with either natural gas, distillate oil, or propane during the first 3 years of operation. After this period, the primary fuel will be natural gas with distillate oil as backup (i.e., no greater than 30 days per year operation on oil). For the purpose of the economic analysis, it was assumed that during the first 3 years of operation natural gas would be utilized 50 percent of the time and distillate oil would be utilized 50 percent of the time.

The NO_x removed using SCR under this assumption would be 233 TPY when firing oil and 125 TPY when firing natural gas; the total NO_x removed would be 358 TPY. If only distillate oil were fired during the first 3 years, then 467 TPY of NO_x would be removed. After the first three years of operation, natural gas would, as a minimum, be used 91.8 percent of the time while oil would at most be utilized up to 8.2 percent of the time. Under this operational scenario, 229 TPY of NO_x would be removed during natural gas firing and 38 TPY of NO_x during distillate oil firing. In order to calculate a cost effectiveness over a twenty year period (i.e., the basis for the economic analysis), the cost effectiveness was weight-adjusted by the number of years under the specific operation scenario.

Economic--The total capital and annualized costs for SCR are presented in Tables 4-5 and 4-6, respectively. The total annualized cost of applying SCR with dry low-NO_x combustion is $1,957,900. The incremental reduction in NO_x emissions is 358 TPY for the first 3 years and 267 TPY after the third year of operation. The incremental cost effectiveness of SCR over dry low-NO_x combustion and water injection is estimated to be $5,463/ton of NO_x removed for the first 3 years and $7,311/ton of NO_x removed for the third to twentieth year of operation. The average cost effectiveness over the entire 20-year period would be $7,034/ton of NO_x removed. Assuming that distillate oil were fired during the entire first 3 years, the cost

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

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
<u>Direct Capital Costs</u>		
SCR Associated Equipment	597,800	Developed from manufacturer budget quotations[a]
Ammonia Storage Tank	165,600	Developed from manufacturer budget quotations[b]
HRSG Modification	291,400	Developed from manufacturer budget quotations[c]
<u>Indirect Capital Costs</u>		
Installation	405,600	20% of SCR associated equipment and catalyst[d]
Engineering, Erection Supervision, Startup, and O&M Training	289,100	10% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG costs, installation labor.[e]
Project Support	159,000	5% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG engineering costs, and installation labor.[f]
Ammonia Emergency Prepardness Program	19,200	Engineering estimate
Liability Insurance	15,900	0.5% SCR equipment and catalyst with contingency, ammonia storage tank, HRSG engineering costs and installation labor.
Interest During Construction	506,100	15% of all direct and indirect capital costs, including catalyst cost[g]
Contingency	505,100	25% of all capital costs[h]
<u>Total Capital Costs</u>	2,954,800	Sum of all capital costs

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

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
<u>Annualized Capital Costs</u>	347,100	Capital recovery of 10% over 20 years, 11.74% per year[i]
<u>Recurring Capital Costs</u>		
SCR Catalyst (Materials and Labor)	1,430,400	Developed from manufacturer budget quotations[j]
Contingency	357,600	25% of recurring capital costs[k]
<u>Total Recurring Capital Costs</u>	1,788,000	Sum of recurring capital costs
<u>Annualized Recurring Capital Costs</u>	719,000	Capital recovery of 10% over 3 years, 40.21% per year[l]

Note: HRSG = heat recovery steam generators.
SCR = selective catalytic reduction.

Footnotes for Table 4-5

Note: All calculations rounded to nearest 100.

a. Developed from various vendor data as an algorithim to account for mass flow (lb/hr) through HRSG.

   The SCR associated cost is made up of 2 factors:

   1. Catalyst Housing, vaporizer, and HRSG wash system is $98.7 per 1,000 lb/hr mass flow at ISO (59°F) conditions.

      $\$98.7 \text{ x } 2{,}384\ 10^{3}\ \text{lb/hr} = \$235{,}300$

   2. Control system costs = $362,500

      Total is $597,800

Table 4-5. Direct and Indirect Capital Cost for Selective Catalytic Reduction (SCR) (Page 3 of 4)

Footnotes for Table 4-5 (continued)

b. Ammonia tank size is based on SCR size as follows:

$69.45/1,000 lb mass flow x 2,384 x 10^3 lb/hr - $165,600

c. HRSG modifications based on mass flow at $122.2 per 1,000 lb mass flow.

$122.22/$10^3$ lb x 2,384 x 10^3 lb/hr - $291,400

d. From EPA OAQPS cost control manual

($597,800 + $1,430,400) x 0.2 - $405,600

e. From EPA OAQPS cost control manual

($597,800 + $165,600 + $1,430,400 + $291,400 + $405,600) x 0.10

- $289,100

f. Engineering estimate; same as engineering costs except use 0.005.

g. From OAQPS cost control manual and engineering estimate.

0.15 x ($597,800 + $165,600 + $291,400 + $405,600 + $289,100

+ $159,000 + $19,200 + $15,900 + $1,430,400) = $506,100

h. From EPA OAQPS cost control manual and engineering estimate

0.20 x ($597,800 + $165,600 + $291,400 + $405,600 + $289,100

+ $159,000 + $19,200 + $15,900 + $506,100) - (0.25 x 0.30

x $1,430,400)

- $505,100; note that the (0.25 x 0.30 x $1,430,400)

removes contingency for catalyst.

i. OAQPS cost control manual; standard statistical tables for 10% interest over 20 years

$2,954,800 x 0.1174 - $347,100

j. Developed from manufacturer data at $0.6/lb mass flow:

$0.6 x 2,384,000 - $1,430,400

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

Footnotes for Table 4-5 (continued)

k. Same rationale as h:

0.25 x $1,430,400 - $357,600

l. Manufacturer guarantees of 3 years life or catalyst. Used OAQPS cost control manual interest of 10 percent over 3 years (40.21 percent per year):

0.4021 x $1,788,000 - $719,000

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

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
<u>Direct Annual Costs</u>		
Operating Personnel	20,800	16 hours/week @ $25/hour[a]
Ammonia	39,700	$300/ton; $NH_3:NO_x$ - 1:1 volume[b]
Accident/Emergency Response Plan	8,100	Consultant estimate, 80 hours/year @ $75/hour plus expenses @ 35% labor[c]
Inventory Cost	56,000	Capital recovery (11.74%/year) for 1/3 of catalyst cost[d]
Catalyst Disposal Cost	66,200	Engineering estimate[e]
Contingency	58,000	20% of indirect costs[f]
<u>Energy Costs</u>		
Electrical	35,000	80 kWh/hr; $0.05/kWh[g]
Heat Rate Penalty	185,000	4" back pressure, heat rate reduction of 0.5%, energy loss at $0.05/kWh[h]
MW Loss Penalty	106,600	84 MW lost for 3 days; lost capacity @ $0.05/kW; cost of natural gas @ $3/MMBtu subtracted[i]
Fuel Escalation Costs	100,000	Real cost increase of fuel [j]
Contingency	80,000	25% of energy costs; excludes fuel escalation[k]
<u>Total Direct Annual Costs</u>	755,400	Sum of all direct annual costs

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

Cost Component	Estimated Cost ($)	Basis for Cost Estimate
Indirect Annual Costs		
Overhead	41,300	60% of ammonia and 115% of O&M labor, and 15% of O&M labor (OAQPS Cost Control Manual)[1]
Property Taxes and Insurance	94,900	2% of total capital costs[m]
Annualized Capital Costs	347,100	Capital recovery of 10% over 20 years, 11.74% per year (from Table 4-5)
Recurring Capital Costs	719,000	Capital recovery of 10% over 3 years, 40.21% per year (from Table 4-5)
Total Indirect Annual Costs	1,202,300	Sum of all indirect annual costs
Total Annual Costs	1,957,700	Total annualized cost[n]

Note: All calculations rounded to the nearest $100.

kW = kilowatt.
kWh = kilowatt-hour.
kWh/hr = kilowatt-hour per hour.
MM/Btu = million British thermal units.
NH_3 = ammonia.
NO_x = nitrogen oxides.
O&M = operation and maintenance.

Footnotes for Table 4-6

Note: all calculations rounded to nearest 100

a. Engineering Estimate:

16 hours/week x 52 weeks/year x $25/hour = $20,800

b. Delivered cost of ammonia at $300/ton

358 TPY removed x $300 x 17/46 (molecular weight of ammonia to NO_x)

= 39,700

Table 4-6. Annualized Cost for Selective Catalytic Reduction (SCR)
(Page 3 of 4)

Cost Component	Estimated Cost ($)	Basis for Cost Estimate

Footnotes for Table 4-6 (continued)

c. 80 hours/yr x $75 x 1.35 = $8,100

d. Required to purchase and store 1/3 of a catalyst for replacement or required.

$1,430,400 x 0.1174 (20 years @ 10 percent) + 3 = $56,000

e. Estimated as $27.77/1,000 lb mass flow; based on catalyst volume.

$27.77 x 2,384 (1,000 lb mass flow) = $66,200

f. OAQPS cost control manual background documents

0.25 x ($20,800 + $39,700 + $8,100 + $56,000 + $66,200) = $58,000

g. 80 kWh/hr from SCR manufacturer; $0.05/kWh is cost of estimated energy:

80 kWh/hr x $8,760 hr/yr x $0.08/kWh = $35,000

h. 4" back pressure from SCR manufacturer; 0.8 percent energy loses from general CT performance curver; 78.83 MW power rating at 150 (59°F) conditions.

84.47 MW x 0.005 x 8,760 hrs/yr x 1,000 kW/mw x $0.05/kWh = $185,000

i. 3 days required to change catalyst or maintenance; saving in gas usage subtracted

84.47 MW x 3 days x 24 hours x $0.05/kWh x 1,000 mwh - (914.53 x 10^6 Btu/hr

x 3 days x 24 hours x $3/$10^6$ Btu) = $106,600

j. Escalation of fuel costs over inflation; 3 percent over 20 years; factor calculated as 0.454565; applies to electrical and heat rate costs only:

0.454565 x ($35,000 + $185,000) = $100,000

k. OAQPS cost control manual background documents

0.25 x ($35,000 + $185,000 x $106,600) = $80,000

l. 0.6 ($39,700 + 1.15 x $20,800) + 0.15 x $20,800 = $41,300

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

Cost Component	Estimated Cost ($)	Basis for Cost Estimate

Footnotes for Table 4-6 (continued)

m. From OAQPS cost control manual

0.02 x ($2,954,800 + $1,788,000) = $94,900

n. Total direct annual costs plus total indirect annual costs:

$755,400 + $1,202,300 = $1,957,700

effectiveness would be \$4,245/ton of NO_x removed (467 tons would be removed). For the entire 20-year period, the cost effectiveness would be \$6,928/ton of NO_x removed.

Environmental--The maximum predicted impacts of the alternative technologies are all considerably below the PSD increment for NO_x of 25 $\mu g/m^3$, annual average, and the AAQS for NO_x, 100 $\mu g/m^3$. Indeed, the impacts are less than the significant impact levels. Additional controls beyond dry low-NO_x combustors (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.

The use of dry low-NO_x combustor technology is truly "pollution prevention". In contrast, 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 based on reported experience; previous permit conditions have specified this level. Ammonia emissions could be as high as 132 TPY. Potential emissions of ammonium sulfate and bisulfate will increase emissions of PM10; up to 23.3 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 emissions including CO_2 would be greater with SCR than that proposed using dry low-NO_x combustion technology.

The replacement of the SCR catalyst will create additional economic and environmental impacts since certain catalysts contain materials that are

Table 4-7. Maximum Potential Emission Differentials TPY With and Without Selective Catalytic Reduction

Pollutants	Project With SCR Primary	 Secondary[a]	 Total	Project Without SCR CT/DB	Difference[b]
Particulate	23 [c]	2.19	25	0	25
Sulfur Dioxide	0	24.09	24	0	24
Nitrogen Oxides	193 [d]	12.05	205	551	(346)
Carbon Monoxide	0	0.72	1	0	1
Volatile Organic Compounds	0	0.11	0	0	0
Ammonia	132 [e]	0.00	132	0	132
Total	349	39.16	388	551	(163)
Carbon Dioxide[f]	--	3,760	3,760	--	3,760

Note: Btu/kWh = British thermal units per kilowatt-hour.
CT = combustion turbine.
DB = duct burner.
MW = megawatt.
% = percent.
SCR = selective catalytic reduction.
TPY = tons per year.

[a] Lost energy of 0.50 MW from heat rate penalty and electrical for 8,760 hours per year operation (0.5% of 84.47 MW plus 0.080 MW). Assumes Florida Power Corp. baseloaded oil-fired unit would replace lost energy. EPA emission factors used for 1% sulfur fuel oil and an assumed heat rate of 10,000 Btu/kWh. Emission factors use were (lb/10^6 Btu): PM = 0.1; SO_2 = 1.1; NO_x = 0.55, CO = 0.033 and VOC = 0.005. Example calculation for PM - 0.50 MW x 10,000 Btu/kwh x 1,000 kw/MW x 8,760 hr/yr x 0.1 lb pm/10^6 Btu + 2,000 lb/ton = 2.19 TPY.

[b] Difference = Total with SCR minus project without SCR.

[c] Assume sulfur reacts with ammonia; 17 TPY H_2SO_4 x 132 (MW of ammonia salt) + 98 (MW of H_2SO_4).

[d] 9 ppm NO_x emissions on gas and 15 ppm NO_x emissions on oil; assumes 50% capacity factor each fuel.

[e] 10 ppm ammonia slip (ideal gas law at actual flow rate from stack): 1,468,004 acfm x 60 m/hr x 10 ppm/10^6 x 2,116.8 lb/ft^2 + 1,545 x 17 (molecular weight of NH_3) + (460 +230) x 8,760 + 2,000.

[f] Reflects differential emissions due to lost energy efficiency with SCR (i.e., 0.50 MW CO_2 calculated based on 85.7% carbon in fuel oil and 18,300 Btu/lb).

listed as hazardous chemical wastes under Resource Conservation and Recovery Act (RCRA) regulations (40 CFR 261).

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 3,700,000 kilowatt hours (kWh) in potential lost generation per year. The energy required by the SCR equipment would be about 700,800 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 5×10^{10} British thermal units per year (Btu/yr) or about 50 million cubic feet per year (ft^3/yr) of natural gas would be required.

4.3.1.4 Proposed BACT and Rationale

The proposed BACT for the project is dry low-NO_x combustion technology. The proposed NO_x emissions level using this technology is 25 ppmvd (corrected to 15 percent oxygen) when firing natural gas. 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 is about $7,000 per ton of NO_x removed. These costs are in the range for other projects that have rejected SCR as unreasonable. This is even more apparent if additional pollutant emissions due to SCR are considered (refer to Table 4-7). The cost effectiveness is over $10,000 per ton of pollutant removed when the emissions (exclusive of CO_2) are considered,

2. 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),
3. The energy impacts of SCR will reduce potential electrical power generation by more than 5 million kWh,
4. The proposed BACT (i.e, dry low-NO_x combustion) provides the most cost effective control alternative and results in low environmental impacts (less than the significant impact levels). Dry low-NO_x combustion 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_x emissions, and
5. The proposed emission limit for duct firing (i.e., 0.16 lb/10^6 Btu) is reasonable given the small HRSG gas flow volume.

4.3.2 CARBON MONOXIDE

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. Table 4-8 presents a listing of LAER/BACT decisions for CO emissions from combustion turbines. 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. For the CT being evaluated, CO emissions will not exceed 20 ppmvd, corrected to dry conditions when firing natural gas under full load conditions and 35 ppmvd when firing distillate oil. For propane, the CO emissions will not exceed 10 ppmvd.

Catalytic oxidation is a post-combustion control that has been employed in CO nonattainment areas where regulations have required CO emission levels

Table 4-8. Summary of BACT Determinations for CO from Gas-fired Turbines

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	CO Emission Limit (lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd	basis)	Control Method	Eff. (%)
Lake Cogen	FL	Nov-91	Combined Cycle	120 MW	—	—	—	42		78 ppmvd for oil firing	—
Pasco Cogen	FL	Nov-91	Combined Cycle	120 MW	—	—	—	42		78 ppmvd for oil firing	—
Florida Power Corporation	FL	Sep-91	Simple Cycle	552 MW	—	—	—	—		25 ppmvd for oil firing	—
Enron Louisana Energy Co	LA	Aug-91	Gas Turbines (2)	78.2 MMBtu/hr	—	5.8	—	60	@ 15% O2	Base Case, No Additional Control	—
Sumas Energy, Inc.	WA	Jun-91	Gas Turbine	80 MW	—	—	—	6	@ 15% O2	CO Catalyst	80.00%
Florida P&L Co. (Martin)	FL	Jun-91	Combined Cycle	860 MW	—	—	—	30		33 ppmvd for oil firing	—
Commonwealth Atlantic LTD Partn	VA	Mar-91	Gas Turbine	1533 MMBtu/hr	—	—	261	30	ppmvd	Combustion control	—
Commonwealth Atlantic LTD Partn	VA	Mar-91	Gas Turbine	1400 MMBtu/hr	—	—	261	30	ppmvd	Combustion control	—
Florida P&L Co. (Ft. Lauderdale)	FL	Mar-91	Combined Cycle	860 MW	—	—	—	30		33 ppmvd for oil firing	—
Hardee Power Station	FL	Dec-90	Combined Cycle	660 MW	—	—	—	10		26 ppmvd for oil firing	—
March Point Cogen	WA	Oct-90	Turbine	80 MW	—	—	—	37	@ 15% O2	Combustion Control	—
Delmarva Power Corporation	DE	Sep-90	Combined Cycle	450 MW	—	—	—	15	ppm	Good Combustion	—
Doswell Limited Partnership	VA	May-90	Turbine	1,261 MMBtu/hr	—	25	—	—		Combustor Design & Operation	—
Fulton Cogeneration Assoc.	NY	Jan-90	GE LM5000	500 MMBtu/hr	0.02	—	—	—		—	—
Arrowhead Cogeneration	VT	Dec-89	Gas Turbine	282.0 MMBtu/hr	—	—	—	50	ppmvd @ iso	Design & Good Combustion Technique	—
JMC Selkirk, Inc.	NY	Nov-89	GE Frame 7	80 MW	—	—	—	25	ppm	Combustion Control	—
Capitol District NRG Ctr	CT	Oct-89	Gas Turbine	738.8 MMBtu/hr	0.112	—	—	—		—	—
Panda-Rosemary Corp.	NC	Sep-89	GE Frame 6	499 MMBtu/hr	0.022	10.8	—	—		Combustion Control	—
Kamine Syracuse Cogen	NY	Sep-89	Turbine	79 MW	0.028	—	—	—		Combustion Control	—
Tropicana Products, Inc.	FL	May-89	Gas Turbine	45.40 MW	—	—	—	10	@ 15% O2	—	—
Empire Energy - Niagara Cogen	NY	May-89	GE Frame 6 (3)	1,248 MMBtu/hr	0.024	—	—	—		Combustion Control	—
Megan-Racine Assoc.	NY	Mar-89	GE LM 5000	430 MMBtu/hr	0.026	—	—	—		Combustion Control	—
Indec/Oswego Hill Cogen	NY	Feb-89	GE Frame 6	40 MW	0.022	—	—	—		Combustion Control	—
Pawtucket Power	RI	Jan-89	Turbine	58 MW	—	—	—	23	@ 15% O2	—	—
Ocean State Power	RI	Jan-89	Combine Cycle	500 MW	—	—	—	25	@ 15% O2	—	—
Champion International	AL	Nov-88	Gas Turbine	35 MW	—	9	—	—		—	—
Long Island Lighting Co	NY	Nov-88	Peaking Units (3)	75 MW	—	—	—	10	ppm	Combustion Control	—
Amtrak	PA	Oct-88	Turbine (2)	20 MW	—	30.76	—	—		—	—
Kamine South Glens Falls	NY	Sep-88	GE Frame 6	40 MW	0.021	—	—	—		Combustion Control	—
Orlando Utilities	FL	Sep-88	Gas Turbine (2)	35 MW	—	—	—	10	@ 15% O2	Combustion Control	—
Delmarva Power Corporation	DE	Aug-88	Turbine (2)	200 MW	—	—	—	15	ppm	Good Combustion	—
Kamine Carthage	NY	Jul-88	GE Frame 6	40 MW	0.022	—	—	—		Combustion Control	—
ADA Cogeneration	MI	Jun-88	Turbine	245.0 MMBtu/hr	0.1	—		—		Water Injection	—

Table 4-8. Summary of BACT Determinations for CO from Gas-fired Turbines

Company Name	State	Date of Permit	Unit/Process Description	Capacity (Size)	CO Emission Limit					Control Method	Eff. (%)
					(lb/MMBtu)	(lb/hr)	(TPY)	(ppmvd	basis)		
CCF-1 Jefferson Station	CT	May-88	Gas Turbines (2)	110 MMBtu/hr	0.605	—	—	—		—	—
TBG/Grumman	NY	Mar-88	Gas Turbine	16 MW	0.181	—	—	—		CO Catalyst	80.00%
Midland Cogeneration Venture	MI	Feb-88	Turbines (12)	984.2 MMBTU/hr	—	26	—	—		Turbine Design	—
Midway-Sunset Cogen	CA	Jan-88	GE Frame 7 (3)	75 MW	—	94	—	—		Proper Combustion	—
Downtown Cogeneration Assoc.	LA	Aug-87	Gas Turbine	71.9 MMBtu/hr	0.048	—	—	—		—	—
San Joaquin Cogen Limited	CA	Jun-87	Gas Turbine	48.6 MW	—	55.25	—	55	@ 15% O2	Combustion Control	—
Cogen Technologies	NJ	Jun-87	GE Frame 6 (3)	40 MW	—	—	—	50	ppmvd @ 15	—	—
Pacific Gas Transmission	OR	May-87	Gas Turbine	14,000 HP	—	6	25	—		—	—
Alaska Elect. Gen. & Trans.	AK	Mar-87	Gas Turbine	80 MW				109	lb/scf fuel	Water Injection	—
Sycamore Cogen	CA	Mar-87	Gas Turbine	75 MW	—	—	—	10	@ 15% O2	CO Catalyst & Comb. Control	—
PG&E, Station T	CA	Aug-86	GE LM5000	396 MMBTU/hr	—	—	—	—		CO Catalyst (No limit indicated)	—
Formosa Plastic Corp.	TX	May-86	GE MS 6001	38.4 MW	—	—	32.4	—		—	—

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).

For duct firing, the specific burner design to control NO_x emissions has commonly established the ability of the burner to meet CO limits. Recent BACT decisions for duct firing have ranged from 0.14 $lb/10^6$ Btu for Tropicana Products, Inc. to 0.2 $lb/10^6$ Btu for the Lake and Pasco Cogen Limited projects. The proposed CO BACT emission limit for the project is 0.1 $lb/10^6$ Btu.

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_3 emissions and concomitant corrosive effects to the stack. In addition, trace metals in the fuel could result in catalyst poisoning during prolonged periods of operation.

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

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

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

For the project, the following alternatives were evaluated for natural gas firing as BACT:

1. Oxidation catalyst at 10 ppmvd; maximum annual CO emissions are 94 TPY assuming 50 percent operation on gas and 50 percent operation on oil;
2. Combustion controls; maximum annual CO emissions are 259 TPY (same assumption on operation).

4.3.2.3 Impact Analysis

Economic--The estimated annualized cost of a CO oxidation catalyst is $1,041,267 (Table 4-9), with a cost effectiveness of about $6,320/ton of CO removed. The cost effectiveness is based on 50 percent operation on gas and 50 percent operation on oil, both at 10 ppmvd. No costs are associated with combustion techniques since they are inherent in the design.

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

Energy--An energy penalty would result from the pressure drop across the catalyst bed. A pressure drop of about 2 inches water gauge would be

Table 4-9. Capital and Annualized Cost for Oxidation Catalyst

Cost Component	Cost ($)	Basis
I. CAPITAL COSTS		
A. DIRECT:		
1. Associated Equipment for Catalyst	173,800	Manufacture Estimate - $1,750 per lb/sec mass flow
2. Exhaust Modification	165,600	Engineering Estimate
3. Installation	331,100	25% of Equipment Costs (I.A.1. & 2., and II.A.)
B. INDIRECT:		
1. Engineering & Supervision	99,300	7.5% of Equipment Costs (I.A.1. & 2., and II.A.)
2. Construction and Field Expense	132,400	10% of Equipment Costs (I.A.1. & 2., and II.A.)
3. Construction Contractor Fee	66,200	5% of Equipment Costs (I.A.1. & 2., and II.A.)
4. Startup & Testing	26,500	2% of Equipment Costs (I.A.1. & 2., and II.A.)
5. Contingency	248,700	25% of Direct and Indirect Capital Costs (I.A, and I.B.1-4)
6. Interest During Construction	334,300	15% of Direct and Indirect Capital Costs, and Recurring Capital Costs (I.A., I.B.1.-4 and II.A.)
TOTAL CAPITAL COSTS	1,578,100	Sum of Direct and Indirect Capital Costs
ANNUALIZED CAPITAL COSTS	185,400	Capital Recovery of 10% over 20 years
II. RECURRING CAPITAL COSTS		
A. Catalyst	985,100	Manufacture Estimate - $1,750 per lb/sec mass flow
B. Contingency	246,300	25% of Recurring Capital Costs (II.A)
TOTAL RECURRING CAPITAL COSTS	1,231,300	Sum of Recurring Capital Costs
ANNUALIZED RECURRING CAPITAL COSTS	495,100	Capital Recovery of 10% over 20 years
III. ANNUALIZED COST		
A. DIRECT:		
1. Labor - Operator & Supervisor	5,300	4 hours/week, 52 weeks/year, $22/hour and 15% supervisor cost
2. Maintenance	14,000	0.5% of Total and Recurring Capital Costs
3. Inventory Cost	38,600	Capital Carrying cost (10% over 20 years) for catalyst for 1 CT
B. ENERGY COSTS		
1. Heat Rate Penalty	74,000	0.2% heat rate penalty. $50/MW energy loss
2. MW Loss Penalty (catalyst changeout)	35,500	Loss of 84.43 MW for one day; cost of natural gas at $\$3/10^6$ Btu deducted from cost
3. Fuel Escalation Costs	35,600	Fuel escalation of 3% over inflation; annualized over 20 years
4. Contingency	35,800	25% of energy costs
C. INDIRECT:		
1. Overhead	11,600	60% of Labor and Maintenance Costs (III.A.1. and 2.)
2. Property Taxes	28,100	1% of Total and Recurring Capital Cost
3. Insurance	28,100	1% of Total and Recurring Capital Cost
4. Administration	56,200	2% of Total and Recurring Capital Cost
Annualized Capital Costs	185,400	
Annualized Recurring Capital Costs	495,100	
TOTAL ANNUALIZED COSTS	1,041,267	Sum of Operating and Maintenance and Annualized Capital Costs

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

expected. At a catalyst back pressure of about 2 inches, an energy penalty of about 1,850,000 kWh/yr would result at 100 percent load. This energy penalty is sufficient to supply the electrical needs of about 150 residential customers over a year. To replace this lost energy, about 1.8 x 10^{10} Btu/yr or about 18 million ft^3/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 about one million dollars, with a cost effectiveness of over $6,000/ton of CO removed).

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 since it will not lower CO emissions substantially and will not produce a measurable reduction in the air quality impacts. Indeed, recent BACT decisions for combustion turbines have set limits in the 30 ppmvd range. The cost of an oxidation catalyst would be significant and not cost-effective given the proposed emission limit of 20 ppmvd for the CT when firing gas and 35 ppmvd when firing distillate oil.

For the duct burner, the proposed BACT limit of 0.1 lb/10^6 Btu is lower than that proposed for similar projects.

4.3.3 SULFUR DIOXIDE (SO_2)

4.3.3.1 Emission Control Hierarchy

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

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

The BACT/LAER clearinghouse documents show that fuel sulfur contents from 0.8 percent to less than 0.1 percent have been specified as BACT for CTs. The lowest sulfur-containing fuels were required in California and the Northeastern U.S., where LAER decisions dictated more stringent standards. Furthermore, such requirements generally limited fuel oil use for backup or emergency purposes only.

In Florida, BACT determinations for CTs have restricted sulfur content in oil from 0.2 to 0.3 percent for an annual average period and 0.5 percent for a maximum. These facilities include the Florida Power and Light Company (FPL) Lauderdale Repowering Project, the Hardee Power Station, and the FPL Martin project. Recent cogeneration facilities have been permitted using 0.1 percent sulfur fuel oil for limited periods (i.e., approximately 10 days).

For the proposed CT, the only technically feasible control technology for SO_2 is low sulfur fuel use. The use of natural gas will minimize SO_2 emissions but natural gas is not available in sufficient quantities during the first 3 years to operate the plant at a 100-percent capacity factor. SO_2 emissions from distillate fuel can be minimized by specification of a lower sulfur content fuel. A maximum sulfur content of 0.1 percent was selected as the top-down BACT level since it is in the range of the lowest sulfur contents being permitted by FDER or being recognized in other states as BACT.

4.3.3.2 Technology Description

The No. 2 fuel oil used in the proposed CTs will have a maximum sulfur content specification of 0.1 percent.

4.3.3.3 Impact Analysis

Economic--The estimated cost effectiveness of using 0.1 percent sulfur oil instead of standard No. 2 distillate oil with a maximum 0.5 percent sulfur fuel oil is $3,586 per ton of SO_2 removed. This was calculated assuming an initial difference of 6.9 percent between a specification of standard No. 2 fuel oil and 0.1 percent oil and a fuel escalation rate of 3 percent over inflation.

Environmental--Based upon use of 0.1 percent sulfur fuel oil, the maximum SO_2 impacts of the proposed turbines alone will be less than 6 percent of the AAQS for SO_2 and less than 17 percent of the allowable PSD Class II increments. The predicted impacts to the Chasshowitzka National Wilderness Class I area are less than the EPA significant impact levels. As a result, significant air quality impacts will not occur by using 0.1 percent sulfur fuel oil. The modeling results are contained in Section 7.0.

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

4.3.3.4 Proposed BACT and Rationale

The proposed BACT for the proposed turbine is the use of No. 2 fuel oil with a maximum sulfur content of 0.1 percent. The selection of this control alternative as BACT is consistent with previous determinations by FDER and the regulatory agencies of other states.

4.3.4 VOLATILE ORGANIC COMPOUNDS

4.3.4.1 Emission Control Hierarchy

The VOCs generated from the proposed project will be a result of two separate processes. First, the VOCs emitted by the CT are a result of incomplete combustion. These VOC emissions will be controlled through combustion technology so that emissions will not exceed 7 ppmvd when firing natural gas and propane and 10 ppmvd when firing distillate oil. These emission levels are similar to the BACT emission levels established for other similar sources.

The second source of VOC emissions is the CO_2 absorption vents where some of the solvent used to capture the CO_2 will be emitted. The organic compound that will be emitted is monoethanolamine (MEA, also known as ethanolamine - $H_2NCH_2CH_2OH$). The Material Safety Data Sheet on the solvent is presented in Appendix B. Under current FDER definitions of VOC (as found in Rule 17-2.100 (214), F.A.C.) and as indicated by recently promulgated changes in the definition by EPA (57 Federal Register 3945, February 3, 1992), monoethanolamine is a VOC. However, this compound has a relatively high boiling point and low vapor pressure; its photochemical reactivity is unknown. Review of the EPA BACT clearinghouse data (see Table 4-10) does not reveal any similar sources (i.e., CO_2 recovery plants) but does suggest that a percent reduction from 90 to 98 percent is applicable for VOC sources.

4.3.4.2 Technology Description

The nature of the emissions from the CO_2 absorber would require that the solvent (with MEA) be controlled by a scrubber. The scrubber would be either a packed tower, venturi, or impingement type similar to that presented in Appendix B. These scrubbers will remove at least 90 percent of the solvent from the absorber exhaust. The design basis for the scrubber exhaust is 2.36 lb VOC as carbon per ton of CO_2 produced; this is based on CO_2 plant vendor recommendations.

Table 4-10. Summary of BACT Determinations for VOC Controls from Chemical Processing Industries (Page 1 of 2)

Company Name	State	Date of Permit	Description	Unit/Process Control Method	Control Eff (%)
ADC-II, Ltd.	IA	17-Feb-85	Alchl. Fuel Prod. (Dryer,DDGS)	Vent Scrubber	--
	IA	17-Feb-85	Alchl. Fuel Prod. (Strg. Tnk)	Closed Vent Capture, Vapor Rec.	--
AeroJet Strategic Propulsion	CA	01-Apr-83	Chemical Process	Carbon Absorber	98.00
AKZO Chemie America	TX	19-Aug-85	NOURYSET 200V (Allyl Alchl)	Scrubber	98.80
Allied Corp.	NC	13-Aug-84	Fiber Process Alan 3&4	Condenser Sys. and Distall.	85.00
	NC	13-Aug-84	Fiber Process Alan 5	Condenser Sys. and Distall.	85.00
American Chrome & Chemical Co	TX	29-Dec-82	Scrubber #3	Venturi Scrubber	99.50
	TX	29-Dec-82	Scrubber #2	Venturi Scrubber	95.00
	TX	29-Dec-82	Scrubber #1	Venturi Scrubber	95.00
	TX	29-Dec-82	Scrubber #2	Venturi Scrubber	95.00
	TX	29-Dec-82	Scrubber #2	Venturi Scrubber	95.00
American Hoechst	TX	07-Jul-77	Storage Tank	Condenser and Carbon Absorber	90.00
Arco Chemical Co.	TX	09-Feb-84	Propylene Oxide plant	High Energy Venturi	--
Arco Oil & Gas Co.	TX	04-Apr-86	CO_2 Recovery, Sulfur	SRU Incinerator	--
Bofors Nobel, Inc.	MI	15-Jan-85	Mfg. of MBOCA	Wet Scrubber & Carbon Absorption	99.95
BYK-Chemie, USA	CT	17-Aug-89	Material Transfer, Mixing Tank	Condenser	95.00
	CT	17-Aug-89	Material Transfer, Mixing Tank	Condenser	95.00
Chemical Reclamation Services	TX	10-Jul-87	Pump, Vacuum, Halogen Process	Condenser/Carbon Absorber	--
	TX	10-Jul-87	Tank, Halogen Process	Carbon Absorber	--
	TX	10-Jul-87	Pump, Vacuum, Non-halogen	Condenser/Carbon Absorber	--
	TX	10-Jul-87	Tank, Non-halogen	Carbon Absorber	--
Chem-Trend, Inc.	MI	--	Storage Tank	Vapor Balance System, Zero Emission	100.00
	MI	--	Process. Vat, Filling/Purging	Pressure/Condensation Vapor Rec.	80.00
Chevron Chemical	WA	01-Aug-88	Plant	Auto. pH Trim Control System	--
Circle Energies Corp.	NE	22-Jan-85	Alcohol Fermenter	Packed Scrubber	95.00
Consolidated Energy Group, Lt	IA	13-Nov-81	Alchl. Fuel Production	Scrubbers, Floating Roof	--
Dow Chemical	MI	01-Mar-88	Process Equipment	Vapor Bal., Demister, Incinerator	99.00
	MI	09-Oct-87	Mfg. of Styrene/Butadiene/Latex	Afterburner	99.90
	MI	23-Mar-87	Material Handling	Scrubber, Vapor Bal.,Press. Tanks	--
	CA	12-Nov-86	Phenol/Acetone Storage tank	Spray Scrubber, Carbon Absorber	99.30
Dow Corning Corp.	KY	16-Oct-78	Chlorosilane/Methanol	Vapor Recovery	99.00
Dupont Spruance Plant	VA	15-Dec-86	Dimethyl Acetamide	Solvent Recovery System	99.00
Eli Lilly & Co.	IN	15-Feb-89	Pharmaceutical, Insulin	Low Temp. Venturi Condenser.	97.00
Ethyl Corp.	TX	24-Sep-86	Synth. Fuels/Fuel Conv.	Catalytic Incinerator	98.00
Firestone Tire Co.	GA	13-Nov-80	Synth. Rubber/Rubber Tires	Carbon Absorption	90.00
Georgia-Pacific Corp.	NC	17-Jan-80	Formaldehyde Production	Catalytic Converter	95.00
Globe Manufacturing Co.	NC	26-Jun-84	Elastic Fiber extruding line	Carbon Bed Absorption Units	77.00
	NC	01-Feb-83	Elastic Fiber extruding line	Carbon Bed Absorption Units	78.00
GoodYear Tire & Rubber Co.	TX	10-Jan-85	Butadiene, Mfg. process	Production Steam Stripper	90.00

Table 4-10. Summary of BACT Determinations for VOC Controls from Chemical Processing Industries (Page 2 of 2)

Company Name	State	Date of Permit	Description	Unit/Process Control Method	Control Eff (%)
Hercules Inc.	TX	11-May-87	Material Storage Soln.	Carbon Absorbers	--
	TX	11-May-87	Stabilizer make-up	Carbon Absorbers	--
	TX	11-May-87	Fugitive Emission	Monitoring and Maintenance Prog.	--
	TX	11-May-87	Material Prep. Soln.	Carbon Absorbers	--
	TX	11-May-87	Dryer	Carbon Absorbers	--
	TX	11-May-87	Material Shipping Product	Carbon Absorbers	--
	TX	11-May-87	Neutralizer	Carbon Absorbers	--
Himont USA, Inc.	TX	11-Feb-85	Polypropylene Process	Flare	99.00
Internat. Minerals & Chmcl Co	PA	12-Sep-79	Formaldehyde, Plant	Catalytic Afterburner	90.00
	PA	12-Sep-79	Methanol, Storage Tank	Vapor Recovery	90.00
	PA	12-Sep-79	Formaldehyde, Storage Tank	Vapor Recovery	90.00
Monsanto Co.	FL	26-Mar-81	Maleic Anhydride	Incineration	90.00
New England Ethanol, Inc.	ME	10-Aug-83	Ethanol (Truck & Rail Trnsfr)	Vapor Recovery	95.00
	ME	10-Aug-83	Aldehyde (Storage Tank)	Vapor Recovery	95.00
	ME	10-Aug-83	Ethanol (Storage Tank)	Vapor Recovery	95.00
	ME	10-Aug-83	Cyclohexane (Storage Tank)	Vapor Recovery	95.00
	ME	10-Aug-83	Gasoline/Diesel (Storage Tank)	Vapor Recovery	95.00
	ME	10-Aug-83	Oil (Storage Tank)	Vapor Recovery	95.00
North American Reiss Corp.	VA	17-Apr-87	Silicone Plastic Manu.	--	--
	VA	17-Apr-87	Solvent, Synthetic Fibers	--	--
Perstorp Polyvols	OH	01-Feb-89	Formaldehyde, Process	Catalytic Incinerator.	98.00
	OH	24-Aug-88	Formaldehyde, Tank	Catalytic Incinerator.	98.00
	OH	24-Aug-88	IMP and Formate	Catalytic Incinerator.	98.00
	OH	24-Aug-88	Butyraldehyde, Tank	Sub fill/Pressurized tank	--
Pittsylvania County	VA	06-Dec-88	Maleic Anhydride	Wet Scrubber	--
PMC Specialities Grp, Prodn D	CA	27-Oct-86	Phenol/Acetone Dryer/Cryst.	Incinerator	90.00
Sohio Chemical Co.	TX	04-Jun-84	Acrylonitrile production	Waste Gas Incinerator	99.80
Standard Oil Company	TX	14-Dec-87	Maleic Anhydride	Incinerator	99.60
3 M	IL	05-Feb-88	Fluorocarbons, Chem. Prod.	Condensers(-40F), Work Practice	--
Union Carbide Chemical	TX	11-Aug-88	Carbon Absorber	--	98.00
	TX	11-Aug-88	Fugitives	--	--
	TX	11-Aug-88	Acetic Acid, Tank	--	--
Velsicol Chemical Co.	TN	08-Oct-82	Expansion Plant	Wet Scrubber, Carbon Absorption	98.00
	TN	08-Oct-82	Benzyl Chloride Synthsis	Wet Scrubber, Carbon Absorption	80.00
	TN	08-Oct-82	Benzotrichloride synthsis	Wet Scrubber, Carbon Absorption	99.00
	TN	08-Oct-82	Benzyl Chloride Synthsis	Wet Scrubber, Carbon Absorption	80.00
Virginia Chemicals, Inc.	VA	05-Dec-86	Polyacrylic power	Uncontrolled	99.90
Wyckoff Chemicals Co., Inc.	MI	06-Jan-89	Pharmaceutical, Solvent	Caustic Scrubber/Demister,Carbon Adsorption	95.00
Yale Rubber Manufacturing Co.	MI	28-Jan-88	Synthetic Rubber/Rubber Tires	Regenerable Carbon Absorption	99.99
	Mi	28-Jan-88	Synthetic Rubber/Rubber Tires	Regenerable Carbon Absorption	99.99

4.3.4.3 Impact Analysis

Economic--The annualized cost of installing a scrubber of the type presented in Appendix B is $240,614. Table 4-11 presents the capital cost and Table 4-12 the operating and annualized costs. The cost effectiveness is estimated at approximately $400 per ton of VOC removed based on an uncontrolled emission rate of approximately about 645.4 TPY.

Environmental--The emissions of MEA were evaluated based on the maximum ground-level impacts and comparisons against the FDER no-threat-levels (NTLs) for toxic air pollutants. The results of this analysis, which is presented in Section 7.0, indicate that the potential impacts of MEA are below the NTLs recommended by the FDER.

Energy--The scrubber system will use approximately 14 kilowatts (kW) per hour or approximately 120,000 kW per hour per year. This energy is sufficient to supply electrical energy to approximately 10 residential customers for a year. This amount is relatively small.

4.3.4.4 Proposed BACT and Rationale

The proposed BACT for VOCs is combustion controls for the CT and scrubber for the CO_2 absorber exhausts. The selection of these control alternatives is based upon the following:

1. Combustion controls have been overwhelmingly approved as BACT for CTs. The proposed VOC emission limits for the CT are in the range approved for other similar sources. No additional controls have been installed for CTs that would substantially reduce VOC emissions. The environmental affect of reduced emissions would not be significant.
2. The proposed scrubber for the CO_2 absorber exhausts will remove VOC in the range of that approved as BACT for a wide range of VOC sources. BACT determinations for similar sources are not available in the BACT clearing house; therefore, the proposed level of control appears appropriate given the range of removal efficiencies for various VOC sources. The proposed scrubber

Table 4-11. Capital Cost Estimates for a Scrubber System to Control MEA Emissions.

Cost Items	Cost Factors	Scrubber System
DIRECT CAPITAL COSTS (DCC):		
(1) Purchased Equipment		
(a) Basic Equipment		
Scrubber System	Vendor Quote	$85,000
(b) Instrumentation & Controls[a]	0.10 x (1a)	$8,500
(c) Freight[a]	0.05 x (1a-1b)	$4,675
(d) Sales Tax (Florida)	0.06 x (1a-1b)	$5,610
(e) Subtotal	(1a-1d)	$103,785
(2) Direct Installation		
(a) Foundations & Supports[a]	0.06 x (1e)	$6,227
(b) Handling & Erection[a]	0.40 x (1e)	$41,514
(c) Electrical[a]	0.01 x (1e)	$1,038
(d) Piping[a]	0.05 x (1e)	$5,189
(e) Insulation[a]	0.03 x (1e)	$3,114
(f) Painting[a]	0.01 x (1e)	$1,038
(g) Subtotal	(2a-2f)	$58,120
Total DCC:	(1) + (2)	$161,905
INDIRECT CAPITAL COSTS (ICC):		
(1) Indirect Installation		
(a) Engineering & Supervision[a]	0.10 x (DCC)	$16,190
(b) Construction & Field Expenses	0.10 x (DCC)	$16,190
(c) Construction Contractor Fee[a]	0.10 x (DCC)	$16,190
(d) Contingencies	0.125 x (DCC)	$20,238
(2) Other Indirect Costs		
(a) Startup & Testing[a]	0.02 x (DCC)	$3,238
(b) Interest During Construction	15% of DCC	$24,286
Total ICC:	(3) + (4)	$96,333
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC	$258,238

[a] Based on venturi scrubber, from William M. Vatavuk, Estimating Costs of Air Pollution Control, 1990.

Table 4-12. Operating and Annualized Cost Estimate for MEA Scrubber System

Cost Items	Basis	Scrubber System
DIRECT OPERATING COSTS (DOC):		
(1) Operating Labor		
Operator[a]	32 hours per week, $25.0/hr.	$41,600
Supervisor[a]	15% of operator cost	$6,240
(2) Maintenance	10% of TCI	$12,912
(3) Replacement Parts (include freight & tax)	10% of TCI	$12,912
(4) Utilities		
(a) Electricity	$50.0 per MW-hr	$6,002
(b) Water, once-thru	$250 per million gallon	$19,710
(5) Wastewater Treatment	$2.50 per 1,000 gallons	$49,275
(6) Contingencies	10% of DOC	$14,865
Total DOC		$163,516
INDIRECT OPERATING COSTS (IOC):		
(1) Overhead[a]	60% of oper. labor & maint.	$36,451
(2) Property Taxes[a]	1% of total capital investment	$2,582
(3) Insurance[a]	1% of total capital investment	$2,582
(4) Administration[a]	2% of total capital investment	$5,165
Total IOC		$46,781
ANNUALIZED CAPITAL COST (ACC)	CRF of 0.1174 times TCI	$30,317
ANNUALIZED COST (AC):	DOC + IOC + ACC	$240,614

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[a] Based on venturi scrubber, from William M. Vatavuk, Estimating Costs of Air Pollution Control, 1990.

system will be cost effective: in the range of $400 per ton of VOC removed. The environmental impacts at the proposed emission level are below the FDER NTL for the compound being used (i.e., MEA).

4.3.5 OTHER REGULATED AND NONREGULATED POLLUTANT EMISSIONS

The PSD source applicability analysis shows that the PSD significant emissions level is exceeded for PM/PM10 requiring PSD review (including BACT) for these pollutants. The emission of particulates from the CT is a result of incomplete combustion and trace solids in the fuel. The design of the CT ensures that particulate emissions will be minimized by combustion controls and the use of clean fuels. A review of EPA's BACT/LAER Clearinghouse Documents did not reveal any post-combustion particulate control technologies being used on a gas-fueled CT.

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

Therefore, there are no technically feasible methods for controlling the emissions of these pollutants from CTs, other than the inherent quality of the fuel. Natural gas and distillate oil represent BACT for this pollutant.

For the nonregulated pollutants, none of the control technologies evaluated for other pollutants (i.e., SCR) would reduce such emissions; thus, natural gas represents BACT because of its inherent low contaminant 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 SO_2, PM(TSP), PM(PM10), NO_2, CO, VOCs, sulfuric acid mist, Be, and As emissions. Arsenic and sulfuric acid mist may be exempt from monitoring requirements because no acceptable monitoring technique has been established for that pollutant. Except for SO_2 and VOCs, the maximum predicted impacts (emissions in the case of VOCs) from the proposed facility also are less than de minimis levels for the applicable pollutants. Therefore, preconstruction monitoring is not required for those pollutants for this project. For VOC emissions, the maximum emission rate is greater than the de minimis emission rate of 100 TPY.

For SO_2 and ozone concentrations, the monitoring data collected in Polk county are proposed for use to satisfy the preconstruction monitoring requirements. The monitoring data collected at the Mulberry site (SAROAD No. 2860-006-F02) is assumed to represent SO_2 concentrations at the proposed facility's location because the site is located approximately 9.7 km away and is in an area of multiple sources similar to the proposed facility. The 1991 monitoring data collected in Polk county (SAROAD No. 3680-036-J01) is assumed to represent ozone concentrations near the proposed facility. This site is the only ozone monitoring site located in Polk county. The highest, second-highest 1-hour ozone concentration reported at this monitor for 1991 is 0.081 ppm (159.0 $\mu g/m^3$).

Although the proposed facility's impacts are only slightly greater than the de minimis impact and emission levels, the air quality levels are expected to be well below the AAQS after the proposed facility becomes operational. Also, the plant will be permitted to operate with distillate oil on a full-time basis for a 3-year period; however, the plant will be capable of using natural gas and propane during this time. After 3 years, the plant will be fired primarily with natural gas using distillate oil as a backup fuel for less than 1,000 hours per year. Therefore, predicted SO_2 and ozone impacts and emissions will decrease after distillate oil is phased out and used as a backup fuel only.

5.3 BACKGROUND SO_2 CONCENTRATIONS

A background SO_2 concentration must be estimated to account for SO_2 sources which are not explicitly included in the atmospheric dispersion modeling analysis. In order to estimate reasonable background SO_2 concentrations, a review of recent, available SO_2 monitoring data in the area of the proposed project was performed. Presented in Table 5-1 is a summary of ambient SO_2 data available from 1988 to 1991 for monitors located within Polk county. A total of four stations are located in Polk county, all of which have continuous SO_2 monitors. These monitors are operated by the State of Florida.

Table 5-1. Summary of Ambient SO$_2$ Monitoring Data for Sites Located Within Polk County, 1988 to 1991

SAROAD Site No. (Distance from Proposed Facility)	City	Monitoring Method	Period	No. of Obs.	Percent Data Recovery	SO$_2$ Concentration ($\mu g/m^3$)		
						3-Hour[a]	24-Hour[a]	Annual Average
2160-001-F01[c] (27.6)	Lakeland	Continuous	1988	8646	98.4	154	53	11
			1989	1465	16.7	101	37	10
			1990	--	--	--	--	--
3680-010-F02[b] (14.1)	Nichols	Continuous	1988	8510	96.9	212	58	10
			1989	8610	98.3	259	55	10
			1990	8612	98.3	252	62	9
			1991	8542	97.5	167	58	10
2160-004-F02[b] (27.9)	Lakeland	Continuous	1989[d]	5835	66.6	114	29	5
			1990	8683	99.1	122	27	5
2860-006-F02[b] (9.7)	Mulberry	Continuous	1991[e]	7118	81.3	176	40	12

Note:
No. = number.
Obs. = observations.
SO$_2$ = sulfur dioxide.
$\mu g/m^3$ = micrograms per cubic meter.

[a] Second-highest concentrations for calendar year are shown.

[b] Monitoring objective for this site is to measure the impact of air pollution sources.

[c] Monitoring objective for this site is to measure pollutant concentrations indicative of the general population. Monitoring ws discontinued at this site in 1989.

[d] Monitoring began at this site in May 1989.

[e] Monitoring began at this site in February 1991.

Source: FDER, 1988, 1989, 1990.

Site 2860-006-F02, located in Mulberry, is the closest monitoring site to the proposed project (9.7 km) and would thus be most representative of background SO_2 concentrations for the area. Monitoring at this site began in February 1991. Data capture for 1991 was 81.3 percent, just above the 80 percent criteria needed. The highest annual and highest, second-highest short-term concentrations reported for this monitor for 1991 are 176, 40, and 12 $\mu g/m^3$ for the 3-hour, 24-hour, and annual averaging periods, respectively. These background values will be added to modeled impacts for comparison to AAQS.

This monitor is located in an area where existing sources within a 10 km radius have maximum annual SO_2 emissions of greater than 20,000 tons per year. Therefore, the monitoring concentrations reported are expected to include substantial contributions from these sources. Since more than 99 percent of these sources' emissions are included in the modeling analyses, the use of these background values produces a conservative prediction of final impacts near the proposed facility.

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 particular 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

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

Source: EPA, 1990.

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

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

In this analysis, the EPA regulatory options were used to address maximum impacts. Based on a review of the land use around the facility, 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) station at Tampa International Airport. The 5-year period of meteorological data was from 1982 through 1986. The NWS station in Tampa, located approximately 65 km to the west-northwest 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 Tampa using the Holzworth approach (Holzworth, 1972). 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 emission rates for the proposed facility used in the modeling analysis are presented in Tables 6-2 and 6-3. Modeling of the proposed facility demonstrated that the facility's PM, NO_2, and CO impacts are below the significant impact levels. Therefore, further modeling for these pollutants for comparison to AAQS and PSD Class II increments is not required. The facility's impacts are above the SO_2 significant impact levels at a distance of not greater than 700 meters from the proposed CT stack. Therefore, the emission inventories for SO_2 were developed for sources within approximately 51 km of the Mulberry Cogeneration Facility. Using information provided by FDER, the Florida State Air Pollution Information System (APIS), PSD applications, and previous modeling analyses, SO_2 emitting facilities within 51 km of the proposed site were identified. These facilities are presented in Table 6-4.

FDER has recommended a technique for eliminating sources in the modeling analyses if the source's emissions do not meet an emission criteria. The technique is the "Screening Threshold" method, developed by the North

Table 6-2. Stack, Operating, and Emission Data Used in the Air Quality Impact Modeling for the Proposed Mulberry Cogeneration Facility

Parameter	Power Plant 20°F	Power Plant 100°F	CO_2 Plant 20°F	CO_2 Plant 100°F
Stack Data (ft)				
Height	125	125	170	170
Diameter	15	15	3.0	3.0
Operating Data				
Temperature (°F)	220	220	117	117
Velocity (ft/sec)	67.8[a]	55.5[a]	66.5	66.5

			CO_2 Plant							
			20°F				100°F			
			Source				Source			
Maximum Emission Rate (lb/hr)[a,b]	Power Plant 20°F	Power Plant 100°F	CT	DB	CO_2 Abs	Total	CT	DB	CO_2 Abs	Total
SO_2	100.8	78.2	4.9	0.3	0.0	5.20	4.7	0.3	0.0	5.00
PM	14.3	14.3	0.69	0.99	5.0	6.68	0.84	0.99	5.0	6.83
NO_2	173.8	134.8	8.4	15.8	0.0	24.2	8.0	15.8	0.0	23.8
CO	78.8	62.8	3.8	9.9	0.0	13.7	3.7	9.9	0.0	13.6

Note: CT = combustion turbine.
DB = duct burner.
CO_2 Abs = CO^2 absorber.

[a] Exit velocity and emissions from the power plant stack were reduced to account for the mass flow of CT exhaust (120,000 lb/hr) diverted to the CO_2 plant.

[b] Based on burning distillate oil, which produces the highest emission rates among the fuels (distillate oil, natural gas, and propane) selected for this facility.

Table 6-3. Emission Data for Other Regulated and Non-Regulated Pollutants Considered in the Air Quality Impact Modeling for the Proposed Mulberry Cogeneration Facility

			CO_2 Plant							
			20°F				100°F			
			Source				Source			
Maximum Emission Rate (lb/hr)[a,b]	Power Plant 20°F	Power Plant 100°F	CT	DB	CO_2 Abs	Total	CT	DB	CO_2 Abs	Total
Antimony	2.15×10^{-2}	1.67×10^{-2}	1.04×10^{-3}	0.00	0.00	1.04×10^{-3}	9.93×10^{-4}	0.00	0.00	9.93×10^{-4}
Arsenic	4.13×10^{-3}	3.21×10^{-3}	2.00×10^{-4}	0.00	0.00	2.00×10^{-4}	1.91×10^{-4}	0.00	0.00	1.91×10^{-4}
Barium	1.92×10^{-2}	1.49×10^{-2}	9.28×10^{-4}	0.00	0.00	9.28×10^{-4}	8.88×10^{-4}	0.00	0.00	8.88×10^{-4}
Beryllium	2.46×10^{-3}	1.91×10^{-3}	1.19×10^{-4}	0.00	0.00	1.19×10^{-4}	1.14×10^{-4}	0.00	0.00	1.14×10^{-4}
Cadmium	1.03×10^{-2}	8.01×10^{-3}	4.99×10^{-4}	0.00	0.00	4.99×10^{-4}	4.77×10^{-4}	0.00	0.00	4.77×10^{-4}
Chlorine	2.65×10^{-2}	2.06×10^{-2}	1.28×10^{-3}	0.00	0.00	1.28×10^{-3}	1.23×10^{-3}	0.00	0.00	1.23×10^{-3}
Chromium	4.67×10^{-2}	3.63×10^{-2}	2.26×10^{-3}	0.00	0.00	2.26×10^{-3}	2.16×10^{-3}	0.00	0.00	2.16×10^{-3}
Colbalt	8.92×10^{-3}	6.92×10^{-3}	4.31×10^{-4}	0.00	0.00	4.31×10^{-4}	4.12×10^{-4}	0.00	0.00	4.12×10^{-4}
Copper	2.76×10^{-1}	2.14×10^{-1}	1.33×10^{-2}	0.00	0.00	1.33×10^{-2}	1.27×10^{-2}	0.00	0.00	1.27×10^{-2}
Ethanolamine	0.00	0.00	0.00	0.00	147×10^{1}	147×10^{1}	0.00	0.00	147×10^{1}	1.47×10^{1}
Fluoride	3.20×10^{-2}	2.48×10^{-2}	1.54×10^{-3}	0.00	0.00	1.54×10^{-3}	1.48×10^{-3}	0.00	0.00	1.48×10^{-3}
Formaldehyde	3.98×10^{-1}	3.09×10^{-1}	1.92×10^{-2}	3.76×10^{-3}	0.00	2.30×10^{-2}	1.84×10^{-2}	3.76×10^{-3}	0.00	2.22×10^{-2}
Manganese	6.34×10^{-3}	4.92×10^{-3}	3.06×10^{-4}	0.00	0.00	3.06×10^{-4}	2.93×10^{-4}	0.00	0.00	2.93×10^{-4}
Mercury	2.95×10^{-3}	2.29×10^{-3}	1.43×10^{-4}	0.00	0.00	1.43×10^{-4}	1.36×10^{-4}	0.00	0.00	1.36×10^{-4}
Nickel	1.67×10^{-1}	1.30×10^{-1}	8.08×10^{-3}	0.00	0.00	8.08×10^{-3}	7.73×10^{-3}	0.00	0.00	7.73×10^{-3}
Polyorganic Matter	2.74×10^{-4}	2.13×10^{-4}	1.33×10^{-5}	1.10×10^{-4}	0.00	1.24×10^{-4}	1.27×10^{-5}	1.10×10^{-4}	0.00	1.23×10^{-4}
Selenium	2.31×10^{-2}	1.79×10^{-2}	1.12×10^{-3}	0.00	0.00	1.12×10^{-3}	1.07×10^{-3}	0.00	0.00	1.07×10^{-3}
Sulfuric Acid Mist	8.12	6.30	3.92×10^{-1}	2.40×10^{-2}	0.00	4.16×10^{-1}	3.75×10^{-1}	2.40×10^{-2}	0.00	3.99×10^{-1}
Vanadium	6.86×10^{-2}	5.32×10^{-2}	3.31×10^{-3}	0.00	0.00	3.31×10^{-3}	3.17×10^{-3}	0.00	0.00	3.17×10^{-3}
Zinc	6.72×10^{-1}	5.21×10^{-1}	3.25×10^{-2}	0.00	0.00	3.25×10^{-2}	3.11×10^{-2}	0.00	0.00	3.11×10^{-2}

Note:
CT = combustion turbine.
DB = duct burner.
CO_2 Abs = CO^2 absorber.

[a] Exit velocity and emissions from the power plant stack were reduced to account for the mass flow of CT exhaust (120,000 lb/hr) diverted to the CO_2 plant.

[b] Based on burning distillate oil, which produces the highest emission rates among the fuels (distillate oil, natural gas, and propane) selected for this facility.

Table 6-4. SO_2 Emission Inventory of Sources Considered in the Modeling Analysis (Page 1 of 2)

APIS Number	Facility	UTM Coordinates East (km)	UTM Coordinates North (km)	Relative Location to Proposed Facility[a] X (km)	Y (km)	Distance (km)	Direction (degrees)	Screening Threshold Emissions (TPY)[b]	Maximum Allowable Emissions (TPY)	PSD Source?	Included in the AAQS Modeling Analysis?
40TPA530027	IMC-Noralyn Mine Road	414.7	3080.3	1.1	-0.3	1.1	105	9	504	No	Yes
40TPA530053	Farmland Industries	409.5	3080.1	-4.1	-0.5	4.1	263	69	3,878	Yes	Yes
40TPA530065	Kaplan Industries	418.3	3079.3	4.7	-1.3	4.9	105	84	398	No	Yes
40TPA530052	C.F. Industries	408.0	3082.4	-5.6	1.8	5.9	288	104	1,989	Yes	Yes
40TPA530046	W.R. Grace/Seminole Fertilizer	409.8	3086.7	-3.8	6.1	7.2	328	130	8,938	Yes	Yes
40TPA530048	Royster Co.	406.8	3085.1	-6.8	4.5	8.2	303	149	1,284	Yes	Yes
40TPA530054	Agrico Chemical Co. (Pierce)	403.7	3079.0	-9.9	-1.6	10.0	261	187	417	No	Yes
40TPA530055	Agrico Chemical Co. (S. Pierce)	407.5	3071.5	-6.1	-9.1	11.0	214	205	7,722	Yes	Yes
40TPA530051	U.S. Agri-Chemicals	416.0	3069.0	2.4	-11.6	11.8	168	223	4,603	Yes	Yes
40TPA530059	IMC-Praire	402.9	3087.0	-10.7	6.4	12.5	301	235	109	No	No
40TPA530080	Imperial Phosphate	404.8	3069.5	-8.8	-11.1	14.2	218	269	275	No	Yes
40TPA530167	Laidlaw Env. Services[c]	422.7	3091.9	9.1	11.3	14.5	39	276	240	No	No
40TPA530057	Conserve Chemicals	398.7	3084.2	-14.9	3.6	15.3	284	293	1,597	Yes	Yes
40TPA530047	Mobil Chemical Co.-Nichols	398.4	3085.3	-15.2	4.7	15.9	287	304	755	Yes	Yes
40TPA530059	IMC-New Wales	396.7	3079.4	-16.9	-1.2	16.9	266	325	13,884	Yes	Yes
40TPA530044	Gardinier	415.3	3063.3	1.7	-17.3	17.4	174	334	1,173	No	Yes
40HIL290102	Mobil Oil Big Four Mine	394.7	3069.6	-18.9	-11.0	21.9	240	423	569	No	Yes
NA	AMAX	394.8	3067.7	-18.8	-12.9	22.8	236	442	589	Yes	Yes
NA	Hardee Power Station	404.8	3057.4	-8.8	-23.2	24.8	201	482	9,649	Yes	Yes
40HIL290075	Consolidated Minerals	393.8	3096.3	-19.8	15.7	25.3	308	491	1,344	No	Yes
40TPA530004	Lakeland City Power	409.2	3106.2	-4.4	25.6	26.0	350	506	30,496	Yes	Yes
40TPA530003	Lakeland City Power	409.0	3106.2	-4.6	25.6	26.0	350	506	4,375	Yes	Yes
40HIL290101	IMC-Fort Lonesome	389.5	3067.9	-24.1	-12.7	27.2	242	531	1,386	Yes	Yes
40TPA530002	Citrus World	441.0	3087.3	27.4	6.7	28.2	76	550	877	No	Yes
40TPA250009	Wachula City Power Plant	418.4	3047.0	4.8	-33.6	33.9	172	665	180	No	No

Table 6-4. SO_2 Emission Inventory of Sources Considered in the Modeling Analysis (Page 2 of 2)

		UTM Coordinates		Relative Location to Proposed Facility[a]							
APIS Number	Facility	East (km)	North (km)	X (km)	Y (km)	Distance (km)	Direction (degrees)	Screening Threshold Emissions (TPY)[b]	Maximum Allowable Emissions (TPY)	PSD Source?	Included in the AAQS Modeling Analysis?
40TPA530019	Citrus Hill	447.9	3068.3	34.3	-12.3	36.4	110	715	411	No	No
40TPA250011	American Orange Corp.	429.8	3047.3	16.2	-33.3	37.0	154	727	198	No	No
40TPA530001	Alcoma Packing	451.6	3085.5	38.0	4.9	38.3	83	752	327	No	No
NA	C. F. Industries	388.0	3116.0	-25.6	35.4	43.7	324	860	3,796	Yes	Yes
40HIL290261	Hillsborough Co. Res. Rec.	368.2	3092.7	-45.4	12.1	47.0	285	926	744	Yes	No
52FTM280003	FPL-Avon Park	451.4	3050.5	37.8	-30.1	48.3	129	952	67	No	No
40HIL290076	Delta Asphalt	372.1	3105.4	-41.5	24.8	48.3	301	953	51	No	No

Note: APIS = Florida Air Pollution Inventory System.
km = kilometer.
NA = not available or unknown.
SO_2 = sulfur dioxide.
TPY = tons per year.

[a] Proposed facility located at 413.6 km east and 3080.6 km north.

[b] Screening threshold emissions (Q) are equal to 20 times the distance from the source in question to the edge of the proposed facility's SO2 significant impact area (0.7 km). Sources with maximum allowable emissions less than Q were eliminated from the AAQS modeling analysis (see text for details).

[c] Formerly Tricil Recovery Services.

Carolina Department of Natural Resources and Community Development, and approved by the EPA (refer to Appendix C). The method is designed to objectively eliminate from the emission inventory those sources which are not likely to have a significant interaction with the source undergoing evaluation. In general, sources that should be considered in the modeling analyses are those with emissions greater than Q (in TPY) which is calculated by the following criteria:

$$Q = 20 \times D$$

where D is:

1. the distance (km) from the proposed facility to the source undergoing evaluation for short-term analysis, or
2. the distance (km) from the edge of the proposed facility's significant impact area (0.7 km) to the source undergoing evaluation for long-term analysis.

For this analysis the long-term criteria was used since less sources would be eliminated than with the short-term criteria and would thus result in a more conservative approach. Referencing Table 6-4, those sources with maximum allowable SO_2 emissions which are below the calculated "screening threshold" emissions were eliminated from further consideration in the AAQS modeling analysis.

PSD sources are also noted in Table 6-4. These sources were identified from inventories provided by FDER. All PSD sources within 51 km of the proposed facility were explicitly modeled in the PSD Class II analysis.

The individual emissions, stack, and operating parameters for the sources considered in the AAQS analysis are presented in Appendix D, Table D-1. These sources represent all identified facilities within 51 km of the proposed facility. Those facilities eliminated from the modeling analysis using the screening threshold technique are noted.

Where possible, individual sources within a facility were combined in order to obtain a manageable source inventory for modeling purposes. Those facilities located near the proposed Mulberry Cogeneration Facility (i.e., within 5 km) were not combined as to maintain the integrity of the facility's emissions. Sources located more than 5 km from the proposed facility were combined based on like sources within the facility, or sources within the facility which dominate emissions. For the latter case, smaller source's emissions were added and combined with the dominant source's emissions and then modeled using the dominant source's stack and operating parameters. A summary of the combined sources used in the modeling analysis is presented in Appendix D, Table D-2.

A summary of SO_2 sources used in the PSD Class II modeling analysis is presented in Appendix D, Table D-3. These sources were taken from a PSD Class I inventory provided by FDER. Only those sources within 51 km of the proposed facility were used in the Class II analysis.

6.4 RECEPTOR LOCATIONS

As discussed in Section 6.1.1, the general modeling approach considered screening and refined phases to address compliance with AAQS and PSD increments. For the screening phase, concentrations were predicted for the following receptor locations:

1. For determination of the SO_2 significant impact area, 432 receptors located at distances of 300; 500; 700; 1,000; 1,500; 2,000; 3,000; 4,000; 5,000, 7,500; 10,000; and 20,000 m along 36 radials with each radial spaced at 10-degree increments. This grid was centered at the proposed CT stack location.
2. For the AAQS and PSD Class II analysis, 360 total receptors located in a radial grid centered at the proposed CT stack location. These receptors were classified into two main groups:
    a. 36 plant property receptors placed at the nearest plant boundary along 36 radials spaced at 10-degree increments. These receptors are presented in Table 6-5.

Table 6-5. Plant Property Receptors Used in the Screening Modeling Analysis

Receptor Location		Receptor Location	
Direction (degrees)	Distance (meters)	Direction (degrees)	Distance (meters)
10	115	190	104
20	140	200	108
30	188	210	115
40	201	220	122
50	199	230	121
60	116	240	121
70	81	250	125
80	84	260	132
90	92	270	146
100	105	280	145
110	114	290	130
120	122	300	121
130	136	310	117
140	127	320	98
150	114	330	83
160	107	340	86
170	104	350	91
180	104	360	100

Note: Direction and distance are relative to the proposed CT stack.

b. 324 general grid receptors located at distances of 300; 500; 700; 1,000; 1,500; 2,000; 3,000; 4,000; and 5,000 m along 36 radials with each radial spaced at 10-degree increments.

Because the proposed facility's significant impact distance was only 700 m, PSD Class II and AAQS impacts were predicted at a maximum distance of 5 km from the proposed CT stack.

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 1.0 km, the refined receptor grid would consist of receptors at the following locations:

Directions (degrees)	Distance (km)
82, 84, 86, 88, 90, 92, 94, 96, 98	0.8, 0.9, 1.0, 1.1, 1.2, 1.3, and 1.4 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 was determined for the proposed facility alone at 13 discrete receptors located along the boundary of the Class I area. The highest predicted concentrations for the proposed facility for the 5 years of meteorological data were compared with the proposed PSD Class I significance values for SO_2, PM, and NO_2 (see Section 3.2.6).

6.5 BUILDING DOWNWASH EFFECTS

Based on the building dimensions associated with buildings and structures planned at the plant, the stacks for the proposed CT and CO_2 plant 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:

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

$$M_w = 0.886\ W$$

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 6-6. The height of the CT stack and the CO_2 plant stack are greater than $H_b + 0.5\ l_b$ but less than GEP. Therefore, the Huber-Snyder method was used for downwash calculations in the modeling analysis.

6.6 BACKGROUND SO_2 CONCENTRATIONS

Background SO_2 concentrations were taken from 1991 monitoring data collected at Mulberry and were assumed to represent background concentrations near the proposed facility. Background values of 176, 40, and 12 $\mu g/m^3$ were added to the modeling results for the 3-hour, 24-hour, and annual averaging periods, respectively. Refer to Section 5.3 for details.

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

Source	Dominant Building	Actual Building Dimensions (m) Length	Actual Building Dimensions (m) Width	Actual Building Dimensions (m) Height	Projected Width[a] (m)	Modeled Building Dimensions (m) Length, Width	Modeled Building Dimensions (m) Height
Proposed Turbine	Steam Generation Building	21.34	10.67	21.34	23.85	21.13	21.34
CO_2 Plant Stack	Steam Generation Building	21.34	10.67	21.34	23.85	21.13	21.34

[a] Diagonal of actual building dimensions.

7.0 AIR QUALITY MODELING RESULTS

7.1 PROPOSED FACILITY ONLY

7.1.1 SIGNIFICANT IMPACT LEVELS

A summary of the maximum concentrations as a result of the proposed facility operating at maximum load conditions and 20°F and 100°F design temperatures are presented in Tables 7-1 and 7-2, respectively. The results are presented for all regulated pollutants to be considered in the modeling analysis. The modeling was performed based on the operating conditions for the two temperatures, because the highest emissions and flow rate occur at the 20°F design condition while the lowest emissions and flow rate occur at the 100°F design condition. This approach will ensure that the maximum impacts from the proposed facility will be obtained either for the maximum emission condition or minimum flow rate (i.e., minimum plume height) condition.

A summary of the refined impacts for the five applicable averaging times, the regulated pollutants, and the two design temperatures are presented in Tables 7-3 and 7-4. Based on these results, a summary of the maximum predicted impacts of regulated pollutants caused by the proposed facility only for comparison to the significant impact and de minimis monitoring levels is presented in Table 7-5.

The maximum predicted 3-hour, 24-hour, and annual SO_2 concentrations due to the proposed facility are 42.5, 15.5, and 0.28 $\mu g/m^3$, respectively. The maximum 3-hour and 24-hour impacts are above the significance and de minimis levels established by EPA and FDER and, therefore, further modeling analysis is required for SO_2 to demonstrate compliance with PSD increments and AAQS.

The maximum predicted 24-hour and annual average PM(TSP) concentrations due to the proposed facility are 2.81 and 0.23 $\mu g/m^3$, respectively. Maximum PM10 impacts are assumed to be identical to the PM(TSP) impacts. Since these maximum concentrations are below the significance and de minimis levels for these pollutants, no further modeling analysis is necessary.

Table 7-1. Maximum Predicted Screening Impacts for Regulated Pollutants for the Proposed Project at Maximum Load and 20°F Design Temperature (Page 1 of 2)

Averaging Period	Year	Maximum Pollutant Concentration ($\mu g/m^3$)[a]						
		Sulfur Dioxide	Nitrogen Dioxide	Particulate Matter	Carbon Monoxide	Sulfuric Acid Mist	Beryllium	Inorganic Arsenic
1-hour	1982	41.4	71.3	12.8	32.3	NM	NM	NM
	1983	41.4	71.4	18.1	37.3	NM	NM	NM
	1984	58.8	101.0	11.4	46.0	NM	NM	NM
	1985	39.6	68.3	11.5	31.0	NM	NM	NM
	1986	28.5	49.1	11.5	23.7	NM	NM	NM
3-hour	1982	23.9	41.3	6.65	NM	NM	NM	NM
	1983	18.1	32.3	8.85	NM	NM	NM	NM
	1984	33.1	57.1	7.31	NM	NM	NM	NM
	1985	23.0	39.6	7.24	NM	NM	NM	NM
	1986	12.1	28.4	7.73	NM	NM	NM	NM
8-hour	1982	11.1	19.1	4.22	8.88	0.88	0.0003	0.0005
	1983	13.8	23.8	4.68	10.8	1.11	0.0003	0.0006
	1984	20.5	35.4	4.85	16.1	1.65	0.0005	0.0008
	1985	15.7	27.0	4.47	12.3	1.26	0.0004	0.0006
	1986	6.03	19.4	5.33	11.0	0.48	0.0002	0.0003
24-hour	1982	4.91	8.47	1.90	NM	0.39	0.0001	0.0002
	1983	5.08	8.75	2.08	NM	0.41	0.0001	0.0002
	1984	11.2	19.4	1.76	NM	0.90	0.0003	0.0005
	1985	9.02	15.6	1.86	NM	0.72	0.0002	0.0004
	1986	3.11	6.94	1.88	NM	0.25	0.0001	0.0001

Table 7-1. Maximum Predicted Screening Impacts for Regulated Pollutants for the Proposed Project at Maximum Load and 20°F Design Temperature (Page 2 of 2)

		Maximum Pollutant Concentration ($\mu g/m^3$)[a]						
Averaging Period	Year	Sulfur Dioxide	Nitrogen Dioxide	Particulate Matter	Carbon Monoxide	Sulfuric Acid Mist	Beryllium	Inorganic Arsenic
Annual	1982	0.25	0.75	0.18	NM	0.020	0.00001	0.00001
	1983	0.19	0.61	0.15	NM	0.015	0.00000	0.00001
	1984	0.24	0.73	0.18	NM	0.019	0.00001	0.00001
	1985	0.24	0.67	0.17	NM	0.019	0.00001	0.00001
	1986	0.28	0.83	0.22	NM	0.022	0.00001	0.00001

Note: All impacts based on emissions using distillate oil at a maximum 0.1 percent sulfur content.

NM = this averaging period not modeled for this pollutant.

[a] Highest concentrations reported for all averaging periods.

Table 7-2. Maximum Predicted Screening Impacts for Regulated Pollutants for the Proposed Project at Maximum Load and 100°F Design Temperature (Page 1 of 2)

Averaging Period	Year	Maximum Pollutant Concentration ($\mu g/m^3$)[a]						
		Sulfur Dioxide	Nitrogen Dioxide	Particulate Matter	Carbon Monoxide	Sulfuric Acid Mist	Beryllium	Inorganic Arsenic
1-hour	1982	45.6	78.7	13.2	36.6	NM	NM	NM
	1983	46.0	79.3	18.5	37.0	NM	NM	NM
	1984	63.2	109	11.7	50.7	NM	NM	NM
	1985	42.2	72.7	11.8	33.9	NM	NM	NM
	1986	34.2	59.0	11.8	27.5	NM	NM	NM
3-hour	1982	26.8	46.2	6.82	NM	NM	NM	NM
	1983	19.1	32.9	9.08	NM	NM	NM	NM
	1984	37.5	64.6	7.48	NM	NM	NM	NM
	1985	26.7	46.1	7.42	NM	NM	NM	NM
	1986	12.5	28.4	7.96	NM	NM	NM	NM
8-hour	1982	12.7	21.9	4.37	10.2	1.02	0.0003	0.0005
	1983	14.6	25.2	4.80	11.7	1.17	0.0004	0.0006
	1984	24.7	42.5	5.01	19.8	1.98	0.0006	0.0010
	1985	19.0	32.8	4.60	15.3	1.53	0.0005	0.0008
	1986	6.67	19.1	5.46	10.9	0.54	0.0002	0.0003
24-hour	1982	5.70	9.83	1.98	NM	0.46	0.0001	0.0002
	1983	6.51	11.2	2.14	NM	0.52	0.0002	0.0003
	1984	15.1	26.0	2.74	NM	1.21	0.0004	0.0006
	1985	10.2	17.6	1.92	NM	0.82	0.0003	0.0004
	1986	3.53	6.96	1.94	NM	2.80	0.0001	0.0001

Table 7-2. Maximum Predicted Screening Impacts for Regulated Pollutants for the Proposed Project at Maximum Load and 100°F Design Temperature (Page 2 of 2)

Averaging Period	Year	Maximum Pollutant Concentration ($\mu g/m^3$)[a]						
		Sulfur Dioxide	Nitrogen Dioxide	Particulate Matter	Carbon Monoxide	Sulfuric Acid Mist	Beryllium	Inorganic Arsenic
Annual	1982	0.25	0.76	0.19	NM	0.020	0.00001	0.00001
	1983	0.19	0.62	0.16	NM	0.015	0.00000	0.00001
	1984	0.24	0.74	0.19	NM	0.019	0.00001	0.00001
	1985	0.23	0.69	0.18	NM	0.019	0.00001	0.00001
	1986	0.27	0.85	0.23	NM	0.022	0.00001	0.00001

Note: All impacts based on emissions using distillate oil at a maximum 0.1 percent sulfur content.

NM = this averaging period not modeled for this pollutant.

[a] Highest concentrations reported for all averaging periods.

Table 7-3. Maximum Predicted Refined Impacts for Regulated Pollutants for the Proposed Project at Maximum Load and 20°F Design Temperature (Page 1 of 2)

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (meters)	Time Period Julian Day	Time Period Hour Ending	Time Period Year
Sulfur Dioxide	3-hour	40.5	128	200	59	12	1984
	24-hour	13.6	128	200	59	24	1984
	Annual	0.28	90	1500	--	--	1986
Particulate Matter (TSP)	24-hour	2.21	252	600	251	24	1983
	Annual	0.22	80	700	--	--	1986
Particulate Matter (PM10)	24-hour	2.21	252	600	251	24	1983
	Annual	0.22	80	700	--	--	1986
Nitrogen Dioxide	Annual	0.83	80	700	--	--	1986
Carbon Monoxide	1-hour	57.7	218	200	230	4	1984
	8-hour	21.2	122	200	89	16	1984
Sulfuric Acid Mist	8-hour	2.17	122	200	89	16	1984
	24-hour	1.09	128	200	59	24	1984
	Annual	0.022	90	1500	--	--	1986
Beryllium	8-hour	0.00066	122	200	89	16	1984
	24-hour	0.00033	128	200	59	24	1984
	Annual	0.00001	90	1500	--	--	1986

Table 7-3. Maximum Predicted Refined Impacts for Regulated Pollutants for the Proposed Project at Maximum Load and 20°F Design Temperature (Page 2 of 2)

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b]		Time Period		
			Direction (degrees)	Distance (meters)	Julian Day	Hour Ending	Year
Inorganic Arsenic	8-hour	0.0011	122	200	89	16	1984
	24-hour	0.00056	128	200	59	24	1984
	Annual	0.00001	90	1500	--	--	1986

Note: All impacts based on emissions using distillate oil at a maximum 0.1 percent sulfur content.

[a] Highest concentrations reported for all averaging periods.
[b] Relative to the proposed CT stack.

Table 7-4. Maximum Predicted Refined Impacts for Regulated Pollutants for the Proposed Project at Maximum Load and 100°F Design Temperature

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (meters)	Time Period Julian Day	Time Period Hour Ending	Time Period Year
Sulfur Dioxide	3-hour	42.5	128	200	59	12	1984
	24-hour	15.5	128	139	59	24	1984
	Annual	0.27	90	1500	--	--	1986
Particulate Matter (TSP)	24-hour	2.81	128	139	59	24	1984
	Annual	0.23	80	700	--	--	1986
Particulate Matter (PM10)	24-hour	2.81	128	139	59	24	1984
	Annual	0.23	80	700	--	--	1986
Nitrogen Dioxide	Annual	0.85	80	700	--	--	1986
Carbon Monoxide	1-hour	58.9	218	200	230	4	1984
	8-hour	23.6	122	200	89	16	1984
Sulfuric Acid Mist	8-hour	2.35	122	200	89	16	1984
	24-hour	1.24	128	139	59	24	1984
	Annual	0.022	90	1500	--	--	1986
Beryllium	8-hour	0.00072	122	200	89	16	1984
	24-hour	0.00038	128	139	59	24	1984
	Annual	0.00001	90	1500	--	--	1986
Inorganic Arsenic	8-hour	0.0012	122	200	89	16	1984
	24-hour	0.00063	128	139	59	24	1984
	Annual	0.00001	90	1500	--	--	1986

Note: All impacts based on emissions using distillate oil at a maximum 0.1 percent sulfur content.

[a] Highest concentrations reported for all averaging periods.
[b] Relative to the proposed CT stack.

Table 7-5. Summary of Maximum Regulated Pollutant Concentrations Due to the Proposed Project for Comparison to EPA Significance Levels and Florida No Threat Levels (Page 1 of 2)

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (meters)	Significance Impact Level ($\mu g/m^3$)	*de minimis* Monitoring Level ($\mu g/m^3$)
Sulfur Dioxide	3-hour	42.5	128	200	25	NA
	24-hour	15.5	128	139	5	13
	Annual	0.28	90	1500	1	NA
Particulate Matter (TSP)	24-hour	2.81	128	139	5	10
	Annual	0.23	80	700	1	NA
Particulate Matter (PM10)	24-hour	2.81	128	139	5	10
	Annual	0.23	80	700	1	NA
Nitrogen Dioxide	Annual	0.85	80	700	1	14
Carbon Monoxide	1-hour	58.9	218	200	2000	NA
	8-hour	23.6	122	200	500	575
Sulfuric Acid Mist	8-hour	2.35	122	200	NA	NM
	24-hour	1.24	128	139	NA	NM
	Annual	0.022	90	1500	NA	NM
Beryllium	8-hour	0.00072	122	200	NA	NA
	24-hour	0.00038	128	139	NA	0.001
	Annual	0.00001	90	1500	NA	NA

Table 7-5. Summary of Maximum Regulated Pollutant Concentrations Due to the Proposed Project for Comparison to EPA Significance Levels and Florida No Threat Levels (Page 2 of 2)

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (meters)	Significance Impact Level ($\mu g/m^3$)	*de minimis* Monitoring Level ($\mu g/m^3$)
Inorganic Arsenic	8-hour	0.0012	122	200	NA	NM
	24-hour	0.00063	128	139	NA	NM
	Annual	0.00001	90	1500	NA	NM

Note: All impacts based on emissions using distillate oil at a maximum 0.1 percent sulfur content. Concentrations reported are the highest of the 20°F or 100°F design case and represent refined values.

NA = not applicable.
NM = no ambient measurement method.

[a] Highest concentrations reported for all averaging periods.
[b] Relative to the proposed CT stack.

The maximum predicted annual NO_2 concentration due to the proposed facility is 0.85 $\mu g/m^3$. Because this level of impact is below the significance and de minimis levels, no further modeling analysis was performed.

The maximum predicted 1- and 8-hour average CO concentrations due to the proposed facility are 58.9 and 23.6 $\mu g/m^3$, respectively. These maximum impacts are less than the CO significance impact levels. Because the maximum predicted impacts due to the proposed facility are less than the CO significance and de minimis levels, additional modeling is not required for this pollutant.

The maximum 24-hour Be concentration due to the proposed facility is predicted to be 0.00038 $\mu g/m^3$. No significance level has been established for Be, but a de minimis monitoring concentration has been set at 0.001 $\mu g/m^3$, 24-hour average. Since the predicted impacts due to the proposed facility only are well below the de minimis, no further PSD modeling analysis was conducted. Beryllium was addressed as a toxic air pollutant for comparison to the Florida NTLs (refer to Section 7.1.3).

No significance levels have been established for sulfuric acid mist or As. There is also no ambient measurement method established for these pollutants and, thus, no de minimis monitoring concentration. Therefore, no further PSD modeling analysis was conducted. These pollutants were addressed as toxic air pollutants for comparison to the Florida NTLs (refer to Section 7.1.3).

7.1.2 PSD CLASS I SIGNIFICANCE ANALYSIS

Maximum SO_2, NO_2, and PM concentrations predicted at the PSD Class I area of the Chassahowitzka National Wildlife Area for comparison to EPA's recommended PSD Class I significance levels are presented in Tables 7-6 and 7-7. Separate analyses were performed to predict impacts for the proposed CT at the 20°F design temperature and 100°F design temperature. Based upon

Table 7-6. Maximum Predicted Pollutant Concentrations Due to the Proposed Project at 20°F Design Temperature at the Chassahowitzka NWA for Comparison to PSD Class I Significance Values

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b]		Time Period			EPA's Recommended Class I Significance Value ($\mu g/m^3$)
			Direction (degrees)	Distance (meters)	Julian Day	Hour Ending	Year	
Sulfur Dioxide	3-hour	1.17	340700	3171900	176	24	1982	1.23
		0.94	342000	3174000	336	24	1983	
		0.65	340300	3165700	194	3	1984	
		0.67	340300	3167700	64	3	1985	
		0.71	340300	3169800	345	3	1986	
	24-hour	0.16	340700	3171900	210	24	1982	0.275
		0.13	342000	3174000	336	24	1983	
		0.15	341100	3183400	110	24	1984	
		0.12	343700	3178300	335	24	1985	
		0.16	343000	3176200	344	24	1986	
	Annual	0.0106	340700	3171900	NA	NA	1982	0.1
		0.0079	342000	3174000	NA	NA	1983	
		0.0060	340300	3165700	NA	NA	1984	
		0.0070	340700	3171900	NA	NA	1985	
		0.0086	340300	3165700	NA	NA	1986	

Table 7-6. Maximum Predicted Pollutant Concentrations Due to the Proposed Project at 20°F Design Temperature at the Chassahowitzka NWA for Comparison to PSD Class I Significance Values

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (meters)	Time Period Julian Day	Time Period Hour Ending	Time Period Year	EPA's Recommended Class I Significance Value ($\mu g/m^3$)
Particulate Matter (TSP)	24-hour	0.041	340700	3171900	210	24	1982	1.35
		0.030	342000	3174000	336	24	1983	
		0.032	341100	3183400	110	24	1984	
		0.024	343700	3178300	335	24	1985	
		0.035	343000	3176200	344	24	1986	
	Annual	0.0023	340700	3171900	NA	NA	1982	0.27
		0.0017	342000	3174000	NA	NA	1983	
		0.0013	340300	3165700	NA	NA	1984	
		0.0015	340700	3171900	NA	NA	1985	
		0.0019	340300	3165700	NA	NA	1986	
Nitrogen Dioxide	Annual	0.020	340700	3171900	NA	NA	1982	0.1
		0.015	342000	3174000	NA	NA	1983	
		0.011	340300	3165700	NA	NA	1984	
		0.013	340700	3171900	NA	NA	1985	
		0.016	340300	3165700	NA	NA	1986	

Note: All impacts based on emissions using distillate oil at a maximum 0.1 percent sulfur content.
NA = not applicable.

[a] Highest concentrations reported for all averaging periods.
[b] In UTM coordinates. Proposed facility location is 413.6 km east and 3080.6 km north.

Table 7-7. Maximum Predicted Pollutant Concentrations Due to the Proposed Project at 100°F Design Temperature at the Chassahowitzka NWA for Comparison to PSD Class I Significance Values

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b]		Time Period			EPA's Recommended Class I Significance Value ($\mu g/m^3$)
			Direction (degrees)	Distance (meters)	Julian Day	Hour Ending	Year	
Sulfur Dioxide	3-hour	0.99	340700	3171900	176	24	1982	1.23
		0.79	342000	3174000	336	24	1983	
		0.55	340300	3165700	194	3	1984	
		0.57	340300	3167700	64	3	1985	
		0.59	340300	3169800	345	3	1986	
	24-hour	0.13	340700	3171900	210	24	1982	0.275
		0.11	342000	3174000	336	24	1983	
		0.12	341100	3183400	110	24	1984	
		0.09	343700	3178300	335	24	1985	
		0.13	343000	3176200	344	24	1986	
	Annual	0.0086	340700	3171900	NA	NA	1982	0.1
		0.0065	342000	3174000	NA	NA	1983	
		0.0049	340300	3165700	NA	NA	1984	
		0.0057	340700	3171900	NA	NA	1985	
		0.0071	340300	3165700	NA	NA	1986	

Table 7-7. Maximum Predicted Pollutant Concentrations Due to the Proposed Project at 100°F Design Temperature at the Chassahowitzka NWA for Comparison to PSD Class I Significance Values

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Receptor Location[b] Direction (degrees)	Receptor Location[b] Distance (meters)	Time Period Julian Day	Time Period Hour Ending	Time Period Year	EPA's Recommended Class I Significance Value ($\mu g/m^3$)
Particulate Matter (TSP)	24-hour	0.043	340700	3171900	210	24	1982	1.35
		0.031	342000	3174000	336	24	1983	
		0.034	341100	3183400	110	24	1984	
		0.024	343700	3178300	335	24	1985	
		0.036	343000	3176200	344	24	1986	
	Annual	0.0023	340700	3171900	NA	NA	1982	0.27
		0.0018	342000	3174000	NA	NA	1983	
		0.0013	340300	3165700	NA	NA	1984	
		0.0015	340700	3171900	NA	NA	1985	
		0.0020	340300	3165700	NA	NA	1986	
Nitrogen Dioxide	Annual	0.017	340700	3171900	NA	NA	1982	0.1
		0.013	342000	3174000	NA	NA	1983	
		0.010	340300	3165700	NA	NA	1984	
		0.011	340700	3171900	NA	NA	1985	
		0.014	340300	3165700	NA	NA	1986	

Note: All impacts based on emissions using distillate oil at a maximum 0.1 percent sulfur content.
NA = not applicable.

[a] Highest concentrations reported for all averaging periods.
[b] In UTM coordinates. Proposed facility location is 413.6 km east and 3080.6 km north.

these results, the 20°F case produces the worst case impacts in the Class I area. Therefore, these results will be used for comparison to the Class I significance levels.

The maximum predicted SO_2 3-hour, 24-hour and annual concentrations in the Class I area are 1.17, 0.16, and 0.011 $\mu g/m^3$, respectively. These predicted impacts are below EPA's recommended Class I significance levels of 1.22, 0.275, and 0.10 $\mu g/m^3$ for the 3-hour, 24-hour, and annual significance levels, respectively.

The maximum predicted PM 24-hour and annual concentrations in the Class I area are 0.041 and 0.0023 $\mu g/m^3$, respectively. These predicted impacts are below the Class I 24-hour and annual significance levels of 1.35 and 0.27 $\mu g/m^3$, respectively.

The maximum predicted NO_2 annual concentration in the Class I area is 0.020 $\mu g/m^3$. This predicted impact is below the Class I annual significance level of 0.10 $\mu g/m^3$.

As the results indicate, the proposed facility's impacts are below EPA's recommended Class I significance values for all averaging periods and modeled pollutants. Therefore, no further Class I modeling analysis was conducted.

7.1.3. TOXIC POLLUTANT ANALYSIS

The maximum impacts of regulated and nonregulated hazardous pollutants that will be emitted in significant amounts by the proposed facility are presented in Table 7-8. These impacts represent the highest impacts of either the 20- or 100-degree design case. The detailed impacts for each pollutant and design case are presented in Appendix E, Table E-1. Pollutants presented were either modeled at their actual emission rates or their impacts derived using a ratio based on the stack emissions from the CT and CO_2 plant. All regulated pollutants or pollutants which had a CT to CO_2 plant emission ratio different from most other pollutants were modeled using their actual emission rates. These pollutants include Be, As,

Table 7-8. Summary of Maximum Concentrations Due to the Proposed Mulberry Cogeneration Facility for the Air Toxic Modeling Analysis (Page 1 of 3)

Pollutant	Averaging Period	Maximum Concentration (μg/m³)[a]	Florida No Threat Level (μg/m³)
Antimony	8-hour	0.0063	5
	24-hour	0.0033	1.2
	Annual	0.000059	0.3
Arsenic	8-hour	0.0012	2
	24-hour	0.00064	0.48
	Annual	0.000011	0.00023
Barium	8-hour	0.0056	5
	24-hour	0.0030	1.2
	Annual	0.000052	50
Beryllium	8-hour	0.00072	0.02
	24-hour	0.00038	0.0048
	Annual	0.000007	0.00042
Cadmium	8-hour	0.0030	0.5
	24-hour	0.0016	0.12
	Annual	0.000028	0.00056
Chlorine	8-hour	0.0078	15
	24-hour	0.0041	3.6
	Annual	0.000072	NE
Chromium	8-hour	0.014	5
	24-hour	0.0072	1.2
	Annual	0.00013	1000
Colbalt	8-hour	0.0026	0.5
	24-hour	0.0014	0.12
	Annual	0.000024	NE
Copper	8-hour	0.081	1
	24-hour	0.043	0.24
	Annual	0.00075	NE
Ethanolamine	8-hour	31.2	80
	24-hour	12.4	19.2
	Annual	1.19	NE

Table 7-8. Summary of Maximum Concentrations Due to the Proposed Mulberry Cogeneration Facility for the Air Toxic Modeling Analysis (Page 2 of 3)

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Florida No Threat Level ($\mu g/m^3$)
Fluoride	8-hour	0.0094	2
	24-hour	0.0049	0.48
	Annual	0.000087	50
Formaldehyde	8-hour	0.12	4.5
	24-hour	0.062	1.08
	Annual	0.0011	0.077
Lead	8-hour	0.0026	1.5
	24-hour	0.0014	0.36
	Annual	0.000024	0.09
Manganese	8-hour	0.0019	50
	24-hour	0.0010	12
	Annual	0.000017	NE
Mercury	8-hour	0.00086	0.5
	24-hour	0.00046	0.12
	Annual	0.000008	0.3
Nickel	8-hour	0.049	0.5
	24-hour	0.026	0.12
	Annual	0.00046	0.0042
Polyorganic Matter	8-hour	0.000080	NE
	24-hour	0.000042	NE
	Annual	0.000002	NE
Selenium	8-hour	0.0068	2
	24-hour	0.0036	0.48
	Annual	0.000063	NE
Sulfuric Acid Mist[c]	8-hour	2.35	10
	24-hour	1.24	2.38
	Annual	0.022	NE
Vanadium	8-hour	0.020	0.5
	24-hour	0.011	0.12
	Annual	0.00019	20

Table 7-8. Summary of Maximum Concentrations Due to the Proposed Mulberry Cogeneration Facility for the Air Toxic Modeling Analysis (Page 3 of 3)

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)[a]	Florida No Threat Level ($\mu g/m^3$)
Zinc[b]	8-hour	0.20	50
	24-hour	0.10	12
	Annual	0.002	NE

Note: NE - none established.

[a] Concentration reported is the highest of the impacts predicted for the 20- and 100-degree design case. Refer to Table E-1 in Appendix E for detailed impacts.

[b] As zinc oxide.

[c] Not in current FDER NTL list. NTL in table is based on dividing the time-weighted average by 100 and 420 for the 8-hour and 24-hour NTL, respectively.

sulfuric acid mist, and ethanolamine. Impacts for all other hazardous pollutants were derived by using a ratio method with impacts produced for Be, since the ratio of CT to CO_2 plant emissions for most other hazardous pollutants were the same as that for Be.

The maximum 8-hour, 24-hour, and annual concentrations are compared in Table 7-8 to the Florida NTLs. As shown, the predicted impacts are below the NTLs for all pollutants and averaging times. Therefore, the emissions from the proposed facility are not expected to pose a health risk to the public.

7.2 PSD CLASS II INCREMENT ANALYSIS

Maximum SO_2 concentrations predicted from the screening analysis for comparison to the PSD Class II increments are presented in Table 7-9. Based upon these results, the refined analysis was based on modeling the year during which the overall highest, second-highest 3-hour and 24-hour SO_2 concentrations were predicted in the screening analysis. In addition, any other year that produced an overall highest, second-highest concentration that was within ten percent of this maximum concentration also was refined. As stated earlier, a refined analysis for annual average concentrations was not performed. A summary of the maximum SO_2 PSD Class II increment consumption concentrations predicted in the refined analysis is presented in Table 7-10.

The maximum 3-hour average SO_2 PSD increment consumption from the refined analysis is predicted to be 139 $\mu g/m^3$, which is 27 percent of the maximum allowable PSD Class II increment of 512 $\mu g/m^3$, not to be exceeded more than once per year. The proposed project contributed 0.0 $\mu g/m^3$ to this value. The maximum 24-hour average SO_2 PSD Class II increment consumption is predicted to be 38.8 $\mu g/m^3$, which is 43 percent of the maximum allowable PSD Class II increment of 91 $\mu g/m^3$, not to be exceeded more than once per year. The proposed project contributed 0.0 $\mu g/m^3$ to this total.

The maximum annual average SO_2 PSD increment consumption is predicted to be -0.42 $\mu g/m^3$, which is well below the maximum allowable PSD Class II

Table 7-9. Maximum Predicted SO_2 Concentrations from the Screening Analysis for Comparison to PSD Class II Increments

Averaging Period	Maximum Concentration (μg/m³)	Receptor Location[a] Direction (°)	Receptor Location[a] Distance (km)	Period Julian Day	Period Hour Ending	Period Year
3-Hour[b]	117	270	4.0	239	15	1982
	112	250	5.0	126	15	1983
	117	250	3.0	154	15	1984
	119	250	3.0	118	15	1985
	122	250	3.0	62	15	1986
24-Hour[b]	22.3	270	4.0	157	24	1982
	24.1	220	3.0	45	24	1983
	28.1	240	2.0	177	24	1984
	28.8	250	3.0	179	24	1985
	32.5	250	3.0	98	24	1986
Annual	-0.43	90	5.0	—	—	1982
	-0.84	60	5.0	—	—	1983
	-0.42	210	5.0	—	—	1984
	-1.00	170	5.0	—	—	1985
	-0.53	220	5.0	—	—	1986

Note: Based on the CT operating at maximum load and 100°F design temperature and firing fuel oil with 0.1 percent sulfur content.

— = Not applicable.
μg/m³ = micrograms per cubic meter.

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

Table 7-10. Maximum Predicted SO_2 Concentrations from the Refined Analysis for Comparison to PSD Class II Increments

Averaging Period	Maximum Concentration ($\mu g/m^3$)	Receptor Location[a] Direction (°)	Receptor Location[a] Distance (km)	Period Julian Day	Period Hour Ending	Period Year	PSD Class II Increment
SO_2 Concentrations							
3-Hour[b]	139	250	3.2	157	18	1986	512
24-Hour[b]	38.8	252	3.3	278	24	1986	91
Annual	-0.42	210	5.0	—	—	1984	20

Note: Based on the CT operating at maximum load and 100°F design temperature and firing fuel oil with 0.1 percent sulfur content.

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

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

increment of 20 $\mu g/m^3$. The proposed project contributed 0.08 $\mu g/m^3$ to this value.

7.3 AAQS ANALYSIS

The maximum 3-hour, 24-hour, and annual average total SO_2 concentrations predicted from the screening analysis are presented in Table 7-11. The total concentrations were determined from the impacts of the modeled sources added to the background concentration (refer to Section 5.0). These results show that the maximum SO_2 concentrations due to all sources are below the AAQS for the 3-hour, 24-hour, and annual averaging periods.

Similar to the PSD Class II increment analysis, the refined AAQS analysis was based on modeling the year during which the overall HSH 3-hour and 24-hour concentrations were predicted in the screening analysis and any other years that produced a highest, second-highest concentration within ten percent of this maximum. The maximum SO_2 concentrations predicted in the refined analysis are presented in Table 7-12.

The maximum 3-hour average SO_2 concentration due to all sources from the refined analysis is predicted to be 837 $\mu g/m^3$, which is 64 percent of the AAQS of 1,300 $\mu g/m^3$, not to be exceeded more than once per year. The project contributed 0.0 $\mu g/m^3$ to this maximum 3-hour average concentration.

The maximum 24-hour average SO_2 concentration due to all sources is predicted to be 234 $\mu g/m^3$, which is 90 percent of the 24-hour AAQS of 260 $\mu g/m^3$, not to be exceeded more than once per year. The project contributed 0.0 $\mu g/m^3$ to this maximum 24-hour average concentration.

The maximum annual average SO_2 concentration due to all sources is predicted to be 42.0 $\mu g/m^3$, which is 70 percent of the AAQS of 60 $\mu g/m^3$. The project contributed 0.15 $\mu g/m^3$ to the maximum concentration.

Table 7-11. Maximum Predicted Total SO_2 Concentrations from the Screening Analysis for Comparison to AAQS

	Concentration (μg/m^3)			Receptor Location[a]		Period		
		Total Due To						
Averaging Period	Total	Modeled Sources	Background	Direction (°)	Distance (km)	Julian Day	Hour Ending	Year
3-Hour[b]	717	541	176	330	5.0	255	18	1982
	837	661	176	330	5.0	38	18	1983
	731	555	176	330	5.0	222	21	1984
	757	581	176	340	5.0	4	15	1985
	741	565	176	110	5.0	303	9	1986
24-Hour[b]	192	152	40	340	5.0	234	24	1982
	214	174	40	330	5.0	38	24	1983
	218	178	40	100	5.0	124	24	1984
	234	194	40	340	5.0	43	24	1985
	204	164	40	100	5.0	10	24	1986
Annual	41.8	29.8	12	260	5.0	–	–	1982
	40.1	28.1	12	260	5.0	–	–	1983
	42.0	30.0	12	260	5.0	–	–	1984
	40.7	28.7	12	260	3.0	–	–	1985
	41.8	29.8	12	260	3.0	–	–	1986

Note: Based on the CT operating at maximum load and 100°F design temperature and firing fuel oil with 0.1 percent sulfur content.

– = Not applicable.
μg/m^3 = micrograms per cubic meter.

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

Table 7-12. Maximum Predicted SO_2 Concentrations from the Refined Analysis for Comparison to AAQS

Averaging Period	Concentration (μg/m³) Total	Total due to Modeled Sources	Total due to Background	Receptor Location[a] Direction (°)	Receptor Location[a] Distance (km)	Period Julian Day	Period Hour Ending	Period Year	AAQS
<u>SO_2 Concentrations</u>									
3-Hour[b]	837	661	176	330	5.0	38	18	1983	1,300
24-Hour[b]	234	194	40	340	5.0	43	24	1985	260
Annual	42.0	30.0	12	260	5.0	—	—	1984	60

Note: Based on the CT operating at maximum load and 100°F design temperature and firing fuel oil with 0.1 percent sulfur content.

— = Not applicable.
μg/m³ = micrograms per cubic meter.

[a] Relative to the location of the proposed CT unit.

[b] Highest, second-highest concentrations predicted for this averaging period.

7.4 ADDITIONAL IMPACT ANALYSIS

7.4.1 IMPACTS UPON VEGETATION

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

7.4.1.1 Sulfur Dioxide

The maximum total 3-hour average SO_2 concentration (i.e., impacts due to all modeled sources added to a background concentration) is predicted to be 837 $\mu g/m^3$ (see Table 7-12). This concentration is predicted to occur about 5.0 km to the northwest of the facility and represents the concentration that would occur during the worst-case meteorological conditions of the modeled five years. The maximum 3-hour average ground-level concentration predicted for the other 4 years are 90 percent or less of the maximum concentration. Concentrations decrease with distance beyond the location of the maximum concentration.

The maximum total predicted 24-hour average SO_2 concentration is 234 $\mu g/m^3$ (see Table 7-12) and is located approximately 5.0 km to the northwest of the facility. The maximum total predicated annual SO_2 concentration is 42.0 $\mu g/m^3$ (see Table 7-12). This concentration is predicted to occur 5.0 km to the west of the facility.

These concentrations and averaging times can be compared with SO_2 doses known to adversely affect plant species (see Table 7-13). The expected doses from the proposed project combined with background sources are much lower than doses known to cause a detrimental effect on vegetation.

7.4.1.2 Other Pollutants

Predicted impacts of other regulated pollutants are less than the significant impact levels (see Table 7-5). As a result, no impacts are expected to occur to vegetation as a result of the proposed emissions of other regulated pollutants.

7.4.2 IMPACTS TO SOILS

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

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

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

7.4.3 IMPACTS DUE TO ADDITIONAL GROWTH

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

Table 7-13. Sulfur Dioxide Doses Reported to Affect Plant Species Similar to Vegetation in the Region of the Mulberry Cogeneration Facility

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

7.4.4 IMPACTS TO VISIBILITY

The Mulberry Cogeneration Facility is located approximately 120 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). Worst-case emissions at the 20-degree design temperature were used in order to maximize impacts at the Class I area. The results of the screening analysis are presented in Table 7-14. Based on these results the proposed facility is not expected to significantly impair visibility in the Chassahowitzka Wilderness Area.

Table 7-14. Visibility Analysis for the Mulberry Cogeneration Facility on the PSD Class I Area

```
                  Visual Effects Screening Analysis for
                  Source: MULBERRY COGENERATION FACILITY
                    Class I Area: CHASSAHOWITZKA NWA

                    ***   Level-1 Screening   ***
 Input Emissions for
    Particulates     91.94  TON/YR
    NOx (as NO2)    867.41  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:        120.00 km
     Min. Source-Class I Distance:    120.00 km
     Max. Source-Class I Distance:    152.00 km
     Plume-Source-Observer Angle:      11.25 degrees
     Stability:  6
     Wind Speed:   1.00 m/s

                              R E S U L T S

 Asterisks (*) indicate plume impacts that exceed screening criteria

          Maximum Visual Impacts INSIDE  Class I Area
           Screening Criteria ARE NOT Exceeded
                                          Delta E       Contrast
                                       ===========  ============
 Backgrnd Theta Azi Distance Alpha Crit  Plume   Crit  Plume
 ======== ===== === ======== ===== ====  =====   ====  =====
  SKY       10.  84.   120.0    84. 2.00   .013    .05   .000
  SKY      140.  84.   120.0    84. 2.00   .004    .05  -.000
  TERRAIN   10.  84.   120.0    84. 2.00   .001    .05   .000
  TERRAIN  140.  84.   120.0    84. 2.00   .000    .05   .000

          Maximum Visual Impacts OUTSIDE Class I Area
           Screening Criteria ARE NOT Exceeded
                                          Delta E       Contrast
                                       ===========  ============
 Backgrnd Theta Azi Distance Alpha Crit  Plume   Crit  Plume
 ======== ===== === ======== ===== ====  =====   ====  =====
  SKY       10.  75.   116.2    94. 2.00   .014    .05   .000
  SKY      140.  75.   116.2    94. 2.00   .004    .05  -.000
  TERRAIN   10.  60.   109.7   109. 2.00   .001    .05   .000
  TERRAIN  140.  60.   109.7   109. 2.00   .000    .05   .000
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APPENDIX A

- DESIGN INFORMATION, STACK PARAMETERS, AND EMISSIONS
- STACK, OPERATING, AND EMISSION DATA USED IN THE AIR QUALITY MONITORING
- EXAMPLE CALCULATIONS
- EMISSION FACTORS

Design Information, Stack Parameters, and Emissions

Table A-1. Design Information and Stack Parameters for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load

Data	Gas Turbine Fuel Oil 20of	Gas Turbine Fuel Oil 40oF	Gas Turbine Fuel Oil 59oF	Gas Turbine Fuel Oil 80oF	Gas Turbine Fuel Oil 100oF
A	B	C	D	E	F
General:					
Power (kW)	95,860.0	90,080.0	84,470.0	77,930.0	71,250.0
Heat Rate (Btu/kwh)	10,760.0	10,870.0	10,990.0	11,150.0	11,350.0
Heat Input (mmBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
Fuel Oil (lb/hr)	55,604.0	52,785.4	50,044.5	46,842.0	43,595.0
Fuel:					
Heat Content,LHV (Btu/lb)	18,550	18,550	18,550	18,550	18,550
CT Exhaust:					
Volume Flow (acfm)	1,600,590	1,518,533	1,468,004	1,410,850	1,352,891
Volume Flow (scfm)	585,257	560,297	536,777	510,575	484,289
Mass Flow (lb/hr)	2,605,000	2,492,000	2,384,000	2,261,000	2,134,000
Temperature (oF)	984	971	984	999	1,015
Moisture (% Vol.)	7.53	7.70	8.03	8.72	9.93
Oxygen (% Vol.)	13.22	13.23	13.23	13.18	13.04
Molecular Weight	28.59	28.57	28.53	28.44	28.30
Water Injected (lb/hr)	43,420	40,820	37,300	31,540	23,540
HRSG Stack:					
Volume Flow (acfm)	753,740	721,595	691,304	657,559	623,705
Temperature (oF)	220	220	220	220	220
Diameter (ft)	15.0	15.0	15.0	15.0	15.0
Velocity (ft/sec)	71.1	68.1	65.2	62.0	58.8
Stack Height (ft)	125	125	125	125	125

Source: General Electric, 1991.

Table A-2. Maximum Criteria Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load

Pollutant	Gas Turbine Fuel Oil 20of	Gas Turbine Fuel Oil 40oF	Gas Turbine Fuel Oil 59oF	Gas Turbine Fuel Oil 80oF	Gas Turbine Fuel Oil 100oF
A	B	C	D	E	F
Particulate:					
Basis, lb/hr (manufacturer)	15.0	15.0	15.0	15.0	15.0
lb/hr	15.0	15.0	15.0	15.0	15.0
TPY	65.7	65.7	65.7	65.7	65.7
Sulfur Dioxide:					
Basis, % sulfur	0.1	0.1	0.1	0.1	0.1
lb/hr	105.65	100.29	95.08	89.00	82.83
TPY	462.7	439.3	416.5	389.8	362.8
Nitrogen Oxides:					
Basis, ppm*	42.0	42.0	42.0	42.0	42.0
lb/hr	182.2	173.1	164.0	153.5	142.8
TPY	798.0	758.3	718.2	672.4	625.6
Carbon Monoxide:					
Basis, ppm+	35.0	35.0	35.0	35.0	35.0
lb/hr	82.6	78.9	75.3	71.1	66.6
TPY	361.7	345.6	329.9	311.5	291.5
VOC's:					
Basis, ppm+	10.0	10.0	10.0	10.0	10.0
lb/hr	10.11	9.66	9.22	8.71	8.15
TPY	44.3	42.3	40.4	38.1	35.7
Lead:					
Basis, lb/10E+12 Btu	8.9	8.9	8.9	8.9	8.9
lb/hr	9.18E-03	8.71E-03	8.26E-03	7.73E-03	7.20E-03
TPY	0.040	0.038	0.036	0.034	0.032

* corrected to 15% O2 dry conditions
+ corrected to dry conditions

Table A-3. Maximum Other Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Arsenic	lb/10E+12 Btu (1)	4.2	4.2	4.2	4.2	4.2
	lb/hr	4.33E-03	4.11E-03	3.90E-03	3.65E-03	3.40E-03
	TPY	1.90E-02	1.80E-02	1.71E-02	1.60E-02	1.49E-02
Beryllium	lb/10E+12 Btu (1)	2.5	2.5	2.5	2.5	2.5
	lb/hr	2.58E-03	2.45E-03	2.32E-03	2.17E-03	2.02E-03
	TPY	1.13E-02	1.07E-02	1.02E-02	9.51E-03	8.86E-03
Mercury	lb/10E+12 Btu (1)	3	3	3	3	3
	lb/hr	3.09E-03	2.94E-03	2.78E-03	2.61E-03	2.43E-03
	TPY	1.36E-02	1.29E-02	1.22E-02	1.14E-02	1.06E-02
Fluoride	lb/10E+12 Btu (2)	32.5	32.5	32.5	32.5	32.5
	lb/hr	3.35E-02	3.18E-02	3.02E-02	2.82E-02	2.63E-02
	TPY	1.47E-01	1.39E-01	1.32E-01	1.24E-01	1.15E-01
Sulfuric Acid Mist	% of SO2	5	5	5	5	5
	lb/hr	8.51E+00	8.08E+00	7.66E+00	7.17E+00	6.68E+00
	TPY	3.73E+01	3.54E+01	3.36E+01	3.14E+01	2.92E+01

Sources: (1) EPA, 1990; (2) EPA, 1980

Table A-4. Maximum Non-Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Manganese	lb/10E+12 Btu (1)	6.44	6.44	6.44	6.44	6.44
	lb/hr	6.64E-03	6.31E-03	5.98E-03	5.60E-03	5.21E-03
	TPY	7.97E-04	7.57E-04	7.17E-04	6.72E-04	6.25E-04
Nickel	lb/10E+12 Btu (1)	170	170	170	170	170
	lb/hr	1.75E-01	1.66E-01	1.58E-01	1.48E-01	1.37E-01
	TPY	2.10E-02	2.00E-02	1.89E-02	1.77E-02	1.65E-02
Cadmium	lb/10E+12 Btu (1)	10.5	10.5	10.5	10.5	10.5
	lb/hr	1.08E-02	1.03E-02	9.75E-03	9.12E-03	8.49E-03
	TPY	1.30E-03	1.23E-03	1.17E-03	1.09E-03	1.02E-03
Chromium	lb/10E+12 Btu (1)	47.5	47.5	47.5	47.5	47.5
	lb/hr	4.90E-02	4.65E-02	4.41E-02	4.13E-02	3.84E-02
	TPY	5.88E-03	5.58E-03	5.29E-03	4.95E-03	4.61E-03
Copper	lb/10E+12 Btu (1)	280	280	280	280	280
	lb/hr	2.89E-01	2.74E-01	2.60E-01	2.43E-01	2.26E-01
	TPY	3.47E-02	3.29E-02	3.12E-02	2.92E-02	2.72E-02
Vanadium	pg/J (1)	30	30	30	30	30
	lb/hr	7.19E-02	6.83E-02	6.47E-02	6.06E-02	5.64E-02
	TPY	8.63E-03	8.19E-03	7.77E-03	7.27E-03	6.77E-03
Selenium	pg/J (1)	10.1	10.1	10.1	10.1	10.1
	lb/hr	2.42E-02	2.30E-02	2.18E-02	2.04E-02	1.90E-02
	TPY	2.91E-03	2.76E-03	2.61E-03	2.45E-03	2.28E-03
Polyorganic Matter	pg/J (1)	0.12	0.12	0.12	0.12	0.12
	lb/hr	2.88E-04	2.73E-04	2.59E-04	2.42E-04	2.26E-04
	TPY	3.45E-05	3.28E-05	3.11E-05	2.91E-05	2.71E-05
Formaldehyde	lb/10E+12 Btu (1)	405	405	405	405	405
	lb/hr	4.18E-01	3.97E-01	3.76E-01	3.52E-01	3.28E-01
	TPY	5.01E-02	4.76E-02	4.51E-02	4.22E-02	3.93E-02

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990

Table A-5. Maximum Emissions for Additional Non-Regulated Pollutant
Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load

Pollutant		Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Antimony	pg/J (1)	9.4	9.4	9.4	9.4	9.4
	lb/hr	2.25E-02	2.14E-02	2.03E-02	1.90E-02	1.77E-02
	TPY	9.87E-02	9.37E-02	8.88E-02	8.31E-02	7.74E-02
Barium	pg/J (1)	8.4	8.4	8.4	8.4	8.4
	lb/hr	2.01E-02	1.91E-02	1.81E-02	1.70E-02	1.58E-02
	TPY	8.82E-02	8.37E-02	7.94E-02	7.43E-02	6.91E-02
Colbalt	pg/J (1)	3.9	3.9	3.9	3.9	3.9
	lb/hr	9.35E-03	8.87E-03	8.41E-03	7.88E-03	7.33E-03
	TPY	4.09E-02	3.89E-02	3.69E-02	3.45E-02	3.21E-02
Zinc	pg/J (1)	294	294	294	294	294
	lb/hr	7.05E-01	6.69E-01	6.34E-01	5.94E-01	5.53E-01
	TPY	3.09E+00	2.93E+00	2.78E+00	2.60E+00	2.42E+00
Chlorine	ppm	0.5	0.5	0.5	0.5	0.5
	lb/hr	2.78E-02	2.64E-02	2.50E-02	2.34E-02	2.18E-02
	TPY	1.22E-01	1.16E-01	1.10E-01	1.03E-01	9.55E-02

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Table A-6. Design Information and Stack Parameters for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Natural Gas, Base Load

Data	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A	B	C	D	E	F
General:					
Power (kW)	93,110.0	87,470.0	82,040.0	75,880.0	69,900.0
Heat Rate (Btu/kwh)	10,340.0	10,450.0	10,590.0	10,790.0	11,050.0
Heat Input (mmBtu/hr)	962.8	914.1	868.8	818.7	772.4
Natural Gas (lb/hr)	49,876.1	47,353.3	45,008.7	42,415.4	40,014.2
(cf/hr)	1,013,429	962,170	914,530	861,837	813,047
Fuel:					
Heat Content, LHV (Btu/lb)	19,303	19,303	19,303	19,303	19,303
(Btu/cf)	950	950	950	950	950
CT Exhaust:					
Volume Flow (acfm)	1,546,476	1,495,987	1,446,407	1,393,785	1,341,523
Volume Flow (scfm)	574,219	550,057	527,419	503,020	479,569
Mass Flow (lb/hr)	2,558,000	2,448,000	2,343,000	2,226,000	2,108,000
Temperature (oF)	962	976	988	1,003	1,017
Moisture (% Vol.)	6.10	6.32	6.77	7.75	9.46
Oxygen (% Vol.)	14.03	14.04	14.00	13.85	13.55
Molecular Weight	28.61	28.58	28.53	28.42	28.23
Water Injected (lb/hr)	0	0	0	0	0
HRSG Stack:					
Volume Flow (acfm)	739,524	708,406	679,252	647,829	617,627
Temperature (oF)	220	220	220	220	220
Diameter (ft)	15.0	15.0	15.0	15.0	15.0
Velocity (ft/sec)	69.7	66.8	64.1	61.1	58.3
Stack Height (ft)	125	125	125	125	125

Source: General Electric, 1991.

Table A-7. Maximum Criteria Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Natural Gas, Base Load

Pollutant	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A	B	C	D	E	F
Particulate:					
Basis, lb/hr (manufacturer)	7.00	7.00	7.00	7.00	7.00
lb/hr	7.00	7.00	7.00	7.00	7.00
TPY	30.66	30.66	30.66	30.66	30.66
Sulfur Dioxide:					
Basis, gr/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	2.90	2.75	2.61	2.46	2.32
TPY	12.68	12.04	11.44	10.79	10.17
Nitrogen Oxides:					
Basis, ppm*	25.0	25.0	25.0	25.0	25.0
lb/hr	97.5	92.5	87.8	82.9	78.2
TPY	427.05	404.98	384.53	363.07	342.49
Carbon Monoxide:					
Basis, ppm+	20.0	20.0	20.0	20.0	20.0
lb/hr	47.0	44.9	42.9	40.5	37.9
TPY	205.91	196.78	187.78	177.21	165.81
VOC's:					
Basis, ppm+	7.0	7.0	7.0	7.0	7.0
lb/hr	7.05	6.74	6.43	6.07	5.68
TPY	30.9	29.5	28.2	26.6	24.9
Lead:					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Table A-8. Maximum Other Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid Mist	% of SO2	5	5	5	5	5
	lb/hr	2.33E-01	2.22E-01	2.11E-01	1.98E-01	1.87E-01
	TPY	1.02E+00	9.70E-01	9.22E-01	8.69E-01	8.20E-01

Sources: EPA, 1988; EPA, 1980

Table A-9. Maximum Non-Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Natural Gas, Base Load

Pollutant	Units	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polyorganic Matter	pg/J (1)	0.48	0.48	0.48	0.48	0.48
	lb/hr	1.07E-03	1.02E-03	9.69E-04	9.13E-04	8.62E-04
	TPY	4.70E-03	4.47E-03	4.24E-03	4.00E-03	3.77E-03
Formaldehyde	pg/J (1)	38	38	38	38	38
	lb/hr	8.50E-02	8.07E-02	7.67E-02	7.23E-02	6.82E-02
	TPY	3.72E-01	3.54E-01	3.36E-01	3.17E-01	2.99E-01

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990

Table A-10. Design Information and Stack Parameters for Mulberry Cogeneration Facility- GE PG7111(EA), MNQC, Propane, Base Load

Data	Gas Turbine Propane 20oF	Gas Turbine Propane 40oF	Gas Turbine Propane 59oF	Gas Turbine Propane 80oF	Gas Turbine Propane 100oF
A	B	C	D	E	F
General:					
Power (kW)	97,670.0	91,900.0	86,320.0	79,810.0	73,120.0
Heat Rate (Btu/kwh)	10,740.0	10,850.0	10,980.0	11,140.0	11,340.0
Heat Input (mmBtu/hr)	1,049.0	997.1	947.8	889.1	829.2
Fuel Propane (lb/hr)	52,685.9	50,081.1	47,603.9	44,655.1	41,646.4
(cf/hr)	1,104,185	1,049,595	997,677	935,877	872,822
Fuel:					
Heat Content, LHV (Btu/lb)	19,910	19,910	19,910	19,910	19,910
(Btu/cf)	950	950	950	950	950
CT Exhaust:					
Volume Flow (acfm)	1,583,507	1,530,580	1,480,793	1,422,861	1,365,207
Volume Flow (scfm)	590,460	565,533	542,204	515,628	489,361
Mass Flow (lb/hr)	2,612,000	2,499,000	2,392,000	2,268,000	2,142,000
Temperature (oF)	956	969	982	997	1,013
Moisture (% Vol.)	8.63	8.86	9.24	9.97	11.20
Oxygen (% Vol.)	13.19	13.18	13.16	13.08	12.93
Molecular Weight	28.41	28.38	28.34	28.25	28.11
Water Injected (lb/hr)	53,320	51,160	48,060	42,440	34,450
HRSG Stack:					
Volume Flow (acfm)	760,441	728,338	698,293	664,067	630,238
Temperature (oF)	220	220	220	220	220
Diameter (ft)	15.0	15.0	15.0	15.0	15.0
Velocity (ft/sec)	71.7	68.7	65.9	62.6	59.4
Stack Height (ft)	125	125	125	125	125

Source: General Electric, 1991.

Table A-11. Maximum Criteria Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), MNQC, Propane, Base Load

Pollutant	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A	B	C	D	E	F
Particulate:					
Basis, lb/hr (manufacturer)	6.00	6.00	6.00	6.00	6.00
lb/hr	6.00	6.00	6.00	6.00	6.00
TPY	26.28	26.28	26.28	26.28	26.28
Sulfur Dioxide:					
Basis, gr/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	3.15	3.00	2.85	2.67	2.49
TPY	13.82	13.13	12.49	11.71	10.92
Nitrogen Oxides:					
Basis, ppm*	42.0	42.0	42.0	42.0	42.0
lb/hr	177.8	169.2	160.6	150.8	140.4
TPY	778.76	741.08	703.32	660.49	615.14
Carbon Monoxide:					
Basis, ppm+	10.0	10.0	10.0	10.0	10.0
lb/hr	23.5	22.5	21.5	20.2	18.9
TPY	103.01	98.42	93.96	88.64	82.97
VOC's:					
Basis, ppm+	7.0	7.0	7.0	7.0	7.0
lb/hr	7.06	6.74	6.44	6.07	5.68
TPY	30.9	29.5	28.2	26.6	24.9
Lead:					
Basis	NA	NA	NA	NA	NA
lb/hr	NA	NA	NA	NA	NA
TPY	NA	NA	NA	NA	NA

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

Table A-12. Maximum Other Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), MNQC, Propane, Base Load

Pollutant	Units	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A		B	C	D	E	F
Arsenic	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Beryllium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Mercury	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Fluoride	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Sulfuric Acid	% of SO2	5	5	5	5	5
Mist	lb/hr	2.54E-01	2.42E-01	2.30E-01	2.15E-01	2.01E-01
	TPY	1.11E+00	1.06E+00	1.01E+00	9.44E-01	8.80E-01

Sources: EPA, 1988; EPA, 1980

Table A-13. Maximum Non-Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), MNQC, Propane, Base Load

Pollutant	Units	Gas Turbine Natural Gas 20oF	Gas Turbine Natural Gas 40oF	Gas Turbine Natural Gas 59oF	Gas Turbine Natural Gas 80oF	Gas Turbine Natural Gas 100oF
A		B	C	D	E	F
Manganese	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Nickel	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Cadmium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Chromium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Copper	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Vanadium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Selenium	--	--	--	--	--	--
	lb/hr	NEG.	NEG.	NEG.	NEG.	NEG.
	TPY	NEG.	NEG.	NEG.	NEG.	NEG.
Polyorganic Matter	pg/J (1)	0.48	0.48	0.48	0.48	0.48
	lb/hr	1.17E-03	1.11E-03	1.06E-03	9.92E-04	9.25E-04
	TPY	5.13E-03	4.87E-03	4.63E-03	4.34E-03	4.05E-03
Formaldehyde	pg/J (1)	38	38	38	38	38
	lb/hr	9.26E-02	8.81E-02	8.37E-02	7.85E-02	7.32E-02
	TPY	4.06E-01	3.86E-01	3.67E-01	3.44E-01	3.21E-01

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990

Stack, Operating, and Emission Data Used in the Air Quality Modeling

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Table A-14. Design Information and Stack Parameters for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load (Adjustment to Flow)

Data	Gas Turbine Fuel Oil 20of	Gas Turbine Fuel Oil 40oF	Gas Turbine Fuel Oil 59oF	Gas Turbine Fuel Oil 80oF	Gas Turbine Fuel Oil 100oF
A	B	C	D	E	F
General:					
Power (kW)	95,860.0	90,080.0	84,470.0	77,930.0	71,250.0
Heat Rate (Btu/kwh)	10,760.0	10,870.0	10,990.0	11,150.0	11,350.0
Heat Input (mmBtu/hr)	1,031.5	979.2	928.3	868.9	808.7
Fuel Oil (lb/hr)	55,604.0	52,785.4	50,044.5	46,842.0	43,595.0
Fuel:					
Heat Content,LHV (Btu/lb)	18,550	18,550	18,550	18,550	18,550
CT Exhaust (Adjusted for CO2 plant):					
Volume Flow (acfm)	1,526,858	1,445,409	1,394,112	1,335,971	1,276,814
Volume Flow (scfm)	558,297	533,317	509,758	483,477	457,056
Adjusted Mass Flow (lb/hr)	2,485,000	2,372,000	2,264,000	2,141,000	2,014,000
Temperature (oF)	984	971	984	999	1,015
Moisture (% Vol.)	7.53	7.70	8.03	8.72	9.93
Oxygen (% Vol.)	13.22	13.23	13.23	13.18	13.04
Molecular Weight	28.59	28.57	28.53	28.44	28.30
Mass flow to CO2 plant (lb/hr)	120,000	120,000	120,000	120,000	120,000
Mass Flow Adj. (Design/adjusted)	0.954	0.952	0.950	0.947	0.944
HRSG Stack:					
Volume Flow (acfm)	719,019	686,847	656,507	622,659	588,633
Temperature (oF)	220	220	220	220	220
Diameter (ft)	15.0	15.0	15.0	15.0	15.0
Velocity (ft/sec)	67.8	64.8	61.9	58.7	55.5
Stack Height (ft)	125	125	125	125	125

Source: General Electric, 1991.

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Table A-15. Maximum Criteria Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load (Adjustment to Flow)

Pollutant	Gas Turbine Fuel Oil 20of	Gas Turbine Fuel Oil 40oF	Gas Turbine Fuel Oil 59oF	Gas Turbine Fuel Oil 80oF	Gas Turbine Fuel Oil 100oF
A	B	C	D	E	F
Particulate:					
Basis, lb/hr (manufacturer)	15.0	15.0	15.0	15.0	15.0
lb/hr	14.3	14.3	14.2	14.2	14.2
TPY	62.7	62.5	62.4	62.2	62.0
Sulfur Dioxide:					
Basis, % sulfur	0.1	0.1	0.1	0.1	0.1
lb/hr	100.78	95.46	90.30	84.28	78.17
TPY	441.4	418.1	395.5	369.1	342.4
Nitrogen Oxides:					
Basis, ppm*	42.0	42.0	42.0	42.0	42.0
lb/hr	173.8	164.8	155.7	145.4	134.8
TPY	761.3	721.8	682.0	636.7	590.4
Carbon Monoxide:					
Basis, ppm+	35.0	35.0	35.0	35.0	35.0
lb/hr	78.8	75.1	71.5	67.3	62.8
TPY	345.0	329.0	313.3	294.9	275.1
VOC's:					
Basis, ppm+	10.0	10.0	10.0	10.0	10.0
lb/hr	9.65	9.20	8.76	8.25	7.69
TPY	42.2	40.3	38.4	36.1	33.7
Lead:					
Basis, lb/10E+12 Btu	8.9	8.9	8.9	8.9	8.9
lb/hr	8.76E-03	8.29E-03	7.85E-03	7.32E-03	6.79E-03
TPY	0.038	0.036	0.034	0.032	0.030

* corrected to 15% O2 dry conditions
\+ corrected to dry conditions

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Table A-16. Maximum Other Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load (Adjustment to Flow)

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Arsenic	lb/10E+12 Btu (1)	4.2	4.2	4.2	4.2	4.2
	lb/hr	4.13E-03	3.91E-03	3.70E-03	3.46E-03	3.21E-03
	TPY	1.81E-02	1.71E-02	1.62E-02	1.51E-02	1.40E-02
Beryllium	lb/10E+12 Btu (1)	2.5	2.5	2.5	2.5	2.5
	lb/hr	2.46E-03	2.33E-03	2.20E-03	2.06E-03	1.91E-03
	TPY	1.08E-02	1.02E-02	9.65E-03	9.01E-03	8.36E-03
Mercury	lb/10E+12 Btu (1)	3	3	3	3	3
	lb/hr	2.95E-03	2.80E-03	2.64E-03	2.47E-03	2.29E-03
	TPY	1.29E-02	1.22E-02	1.16E-02	1.08E-02	1.00E-02
Fluoride	lb/10E+12 Btu (2)	32.5	32.5	32.5	32.5	32.5
	lb/hr	3.20E-02	3.03E-02	2.87E-02	2.67E-02	2.48E-02
	TPY	1.40E-01	1.33E-01	1.25E-01	1.17E-01	1.09E-01
Sulfuric Acid Mist	% of SO2	5	5	5	5	5
	lb/hr	8.12E+00	7.69E+00	7.28E+00	6.79E+00	6.30E+00
	TPY	3.56E+01	3.37E+01	3.19E+01	2.97E+01	2.76E+01

Sources: (1) EPA, 1990; (2) EPA, 1980

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Table A-17. Maximum Non-Regulated Pollutant Emissions for Mulberry Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load (Adjustment to Flow)

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Manganese	lb/10E+12 Btu (1)	6.44	6.44	6.44	6.44	6.44
	lb/hr	6.34E-03	6.00E-03	5.68E-03	5.30E-03	4.92E-03
	TPY	2.78E-02	2.63E-02	2.49E-02	2.32E-02	2.15E-02
Nickel	lb/10E+12 Btu (1)	170	170	170	170	170
	lb/hr	1.67E-01	1.58E-01	1.50E-01	1.40E-01	1.30E-01
	TPY	7.33E-01	6.94E-01	6.56E-01	6.13E-01	5.68E-01
Cadmium	lb/10E+12 Btu (1)	10.5	10.5	10.5	10.5	10.5
	lb/hr	1.03E-02	9.79E-03	9.26E-03	8.64E-03	8.01E-03
	TPY	4.53E-02	4.29E-02	4.05E-02	3.78E-02	3.51E-02
Chromium	lb/10E+12 Btu (1)	47.5	47.5	47.5	47.5	47.5
	lb/hr	4.67E-02	4.43E-02	4.19E-02	3.91E-02	3.63E-02
	TPY	2.05E-01	1.94E-01	1.83E-01	1.71E-01	1.59E-01
Copper	lb/10E+12 Btu (1)	280	280	280	280	280
	lb/hr	2.76E-01	2.61E-01	2.47E-01	2.30E-01	2.14E-01
	TPY	1.21E+00	1.14E+00	1.08E+00	1.01E+00	9.36E-01
Vanadium	pg/J (1)	30	30	30	30	30
	lb/hr	6.86E-02	6.50E-02	6.15E-02	5.74E-02	5.32E-02
	TPY	3.00E-01	2.85E-01	2.69E-01	2.51E-01	2.33E-01
Selenium	pg/J (1)	10.1	10.1	10.1	10.1	10.1
	lb/hr	2.31E-02	2.19E-02	2.07E-02	1.93E-02	1.79E-02
	TPY	1.01E-01	9.58E-02	9.06E-02	8.46E-02	7.85E-02
Polyorganic Matter	pg/J (1)	0.12	0.12	0.12	0.12	0.12
	lb/hr	2.74E-04	2.60E-04	2.46E-04	2.29E-04	2.13E-04
	TPY	1.20E-03	1.14E-03	1.08E-03	1.01E-03	9.32E-04
Formaldehyde	lb/10E+12 Btu (1)	405	405	405	405	405
	lb/hr	3.98E-01	3.77E-01	3.57E-01	3.33E-01	3.09E-01
	TPY	1.75E+00	1.65E+00	1.56E+00	1.46E+00	1.35E+00

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1990

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Table A-18. Maximum Emissions for Additional Non-Regulated Pollutant
Cogeneration Facility- GE PG7111(EA), DLN Option, Distillate Oil, Base Load (Adjustment to Flow)

Pollutant		Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Antimony	pg/J (1)	9.4	9.4	9.4	9.4	9.4
	lb/hr	2.15E-02	2.04E-02	1.93E-02	1.80E-02	1.67E-02
	TPY	9.41E-02	8.92E-02	8.44E-02	7.87E-02	7.30E-02
Barium	pg/J (1)	8.4	8.4	8.4	8.4	8.4
	lb/hr	1.92E-02	1.82E-02	1.72E-02	1.61E-02	1.49E-02
	TPY	8.41E-02	7.97E-02	7.54E-02	7.04E-02	6.53E-02
Colbalt	pg/J (1)	3.9	3.9	3.9	3.9	3.9
	lb/hr	8.92E-03	8.45E-03	7.99E-03	7.46E-03	6.92E-03
	TPY	3.91E-02	3.70E-02	3.50E-02	3.27E-02	3.03E-02
Zinc	pg/J (1)	294	294	294	294	294
	lb/hr	6.72E-01	6.37E-01	6.02E-01	5.62E-01	5.21E-01
	TPY	2.94E+00	2.79E+00	2.64E+00	2.46E+00	2.28E+00
Chlorine	ppm	0.5	0.5	0.5	0.5	0.5
	lb/hr	2.65E-02	2.51E-02	2.38E-02	2.22E-02	2.06E-02
	TPY	1.16E-01	1.10E-01	1.04E-01	9.71E-02	9.01E-02

Note: Multiply by 2.324 to convert picogram/Joule (pg/J) to lb/10E+12 Btu.

Source: (1) EPA, 1979

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Table A-19. Maximum Emissions for Criteria Pollutants-
Emissions from CT to CO2 plant (based on 120,000 lb/hr steam to CO2)

Pollutant	Gas Turbine Fuel Oil 20of	Gas Turbine Fuel Oil 40oF	Gas Turbine Fuel Oil 59oF	Gas Turbine Fuel Oil 80oF	Gas Turbine Fuel Oil 100oF
A	B	C	D	E	F
Particulate:					
lb/hr	0.69	0.72	0.76	0.80	0.84
TPY	3.03	3.16	3.31	3.49	3.69
Sulfur Dioxide:					
lb/hr	4.87	4.83	4.79	4.72	4.66
TPY	21.32	21.15	20.96	20.69	20.40
Nitrogen Oxides:					
lb/hr	8.39	8.34	8.25	8.15	8.03
TPY	36.76	36.52	36.15	35.69	35.18
Carbon Monoxide:					
lb/hr	3.80	3.80	3.79	3.77	3.74
TPY	16.66	16.64	16.61	16.53	16.39
VOC's:					
lb/hr	0.47	0.47	0.46	0.46	0.46
TPY	2.04	2.04	2.03	2.02	2.01
Lead:					
lb/hr	4.23E-04	4.20E-04	4.16E-04	4.10E-04	4.05E-04
TPY	1.85E-03	1.84E-03	1.82E-03	1.80E-03	1.77E-03

Table A-20. Maximum Emissions for Other Regulated Pollutants-
Emissions from CT to CO2 plant (based on 120,000 lb/hr steam to CO2)

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Arsenic						
	lb/hr	2.00E-04	1.98E-04	1.96E-04	1.94E-04	1.91E-04
	TPY	8.74E-04	8.67E-04	8.60E-04	8.48E-04	8.37E-04
Beryllium						
	lb/hr	1.19E-04	1.18E-04	1.17E-04	1.15E-04	1.14E-04
	TPY	5.20E-04	5.16E-04	5.12E-04	5.05E-04	4.98E-04
Mercury						
	lb/hr	1.43E-04	1.41E-04	1.40E-04	1.38E-04	1.36E-04
	TPY	6.24E-04	6.20E-04	6.14E-04	6.06E-04	5.98E-04
Fluoride						
	lb/hr	1.54E-03	1.53E-03	1.52E-03	1.50E-03	1.48E-03
	TPY	6.76E-03	6.71E-03	6.65E-03	6.56E-03	6.47E-03
Sulfuric Acid Mist	lb/hr	3.92E-01	3.89E-01	3.86E-01	3.81E-01	3.75E-01
	TPY	1.72E+00	1.70E+00	1.69E+00	1.67E+00	1.64E+00

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Table A-21. Maximum Emissions for Non-Regulated Pollutants-
Emissions from CT to CO2 plant (based on 120,000 lb/hr steam to CO2)

Pollutant	Units	Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Manganese	lb/hr	3.06E-04	3.04E-04	3.01E-04	2.97E-04	2.93E-04
	TPY	1.34E-03	1.33E-03	1.32E-03	1.30E-03	1.28E-03
Nickel	lb/hr	8.08E-03	8.02E-03	7.94E-03	7.84E-03	7.73E-03
	TPY	3.54E-02	3.51E-02	3.48E-02	3.43E-02	3.39E-02
Cadmium	lb/hr	4.99E-04	4.95E-04	4.91E-04	4.84E-04	4.77E-04
	TPY	2.19E-03	2.17E-03	2.15E-03	2.12E-03	2.09E-03
Chromium	lb/hr	2.26E-03	2.24E-03	2.22E-03	2.19E-03	2.16E-03
	TPY	9.89E-03	9.81E-03	9.72E-03	9.59E-03	9.46E-03
Copper	lb/hr	1.33E-02	1.32E-02	1.31E-02	1.29E-02	1.27E-02
	TPY	5.83E-02	5.78E-02	5.73E-02	5.66E-02	5.58E-02
Vanadium	lb/hr	3.31E-03	3.29E-03	3.26E-03	3.22E-03	3.17E-03
	TPY	1.45E-02	1.44E-02	1.43E-02	1.41E-02	1.39E-02
Selenium	lb/hr	1.12E-03	1.11E-03	1.10E-03	1.08E-03	1.07E-03
	TPY	4.88E-03	4.85E-03	4.80E-03	4.74E-03	4.68E-03
Polyorganic Matter	lb/hr	1.33E-05	1.31E-05	1.30E-05	1.29E-05	1.27E-05
	TPY	5.80E-05	5.76E-05	5.71E-05	5.63E-05	5.55E-05
Formaldehyde	lb/hr	1.92E-02	1.91E-02	1.89E-02	1.87E-02	1.84E-02
	TPY	8.43E-02	8.36E-02	8.29E-02	8.18E-02	8.07E-02

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Table A-22. Maximum Emissions for Additional Non-Regulated Pollutants-
Emissions from CT to CO2 plant (based on 120,000 lb/hr steam to CO2)

Pollutant		Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Antimony						
	lb/hr	1.04E-03	1.03E-03	1.02E-03	1.01E-03	9.93E-04
	TPY	4.55E-03	4.51E-03	4.47E-03	4.41E-03	4.35E-03
Barium						
	lb/hr	9.28E-04	9.20E-04	9.12E-04	9.00E-04	8.88E-04
	TPY	4.06E-03	4.03E-03	4.00E-03	3.94E-03	3.89E-03
Colbalt						
	lb/hr	4.31E-04	4.27E-04	4.24E-04	4.18E-04	4.12E-04
	TPY	1.89E-03	1.87E-03	1.86E-03	1.83E-03	1.81E-03
Zinc						
	lb/hr	3.25E-02	3.22E-02	3.19E-02	3.15E-02	3.11E-02
	TPY	1.42E-01	1.41E-01	1.40E-01	1.38E-01	1.36E-01
Chlorine						
	lb/hr	1.28E-03	1.27E-03	1.26E-03	1.24E-03	1.23E-03
	TPY	5.61E-03	5.57E-03	5.52E-03	5.44E-03	5.37E-03

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Table A-23. Stack Parameters for CO2 Facility (Includes Duct Burner on Natural Gas)

Data	Duct Burner Data with Gas Turbine on Oil at Ambient Temperature				
	20of	40oF	59oF	80oF	100oF
A	B	C	D	E	F
General:					
Power (kW)	NA	NA	NA	NA	NA
Heat Rate (Btu/kWh)	NA	NA	NA	NA	NA
Heat Input (mmBtu/hr)	99.0	99.0	99.0	99.0	99.0
Fuel Natural Gas (lb/hr)	5,128.7	5,128.7	5,128.7	5,128.7	5,128.7
(cf/hr)	104,211	104,211	104,211	104,211	104,211
Fuel:					
Heat Content,LHV (Btu/lb)	19,303	19,303	19,303	19,303	19,303
(Btu/cf)	950.0	950.0	950.0	950.0	950.0
From CT and Duct Burner Exhaust:					
Volume Flow (acfm)	33,235	33,235	33,235	33,235	33,235
Volume Flow (scfm)	25,806	25,806	25,806	25,806	25,806
Mass Flow (lb/hr) *	112,500	112,500	112,500	112,500	112,500
Temperature (oF)	220	220	220	220	220
Molecular Weight	28.00	28.00	28.00	28.00	28.00
Amine Absorber Stack:					
Volume Flow (acfm)	28,201	28,201	28,201	28,201	28,201
Temperature (oF)	117	117	117	117	117
Diameter (ft)	3.00	3.00	3.00	3.00	3.00
Velocity (ft/sec)	66.5	66.5	66.5	66.5	66.5
Stack Height (ft)	170	170	170	170	170

* Based on 120,000 lb/hr from CT; 5,000 lb/hr from duct burner; less 12,500 lb/hr (10 %) due to CO2 removal.

Table A-24. Maximum Criteria Pollutant Emissions for CO2 Plant (Without Contribution from CT)

Pollutant	Duct Burner Data with Gas Turbine on Oil at Ambient Temperature				
	20of	40oF	59oF	80oF	100oF
A	B	C	D	E	F
Particulate:					
Basis, lb/MMBtu	0.01	0.01	0.01	0.01	0.01
lb/hr	0.99	0.99	0.99	0.99	0.99
TPY	4.3	4.3	4.3	4.3	4.3
Sulfur Dioxide:					
Basis, gr S/100 cf	1.0	1.0	1.0	1.0	1.0
lb/hr	0.30	0.30	0.30	0.30	0.30
TPY	1.3	1.3	1.3	1.3	1.3
Nitrogen Oxides:					
Basis, lb/MMBtu	0.16	0.16	0.16	0.16	0.16
lb/hr	15.84	15.84	15.84	15.84	15.84
TPY	69.4	69.4	69.4	69.4	69.4
Carbon Monoxide:					
Basis, lb/MMBtu	0.1	0.1	0.1	0.1	0.1
lb/hr	9.9	9.9	9.9	9.9	9.9
TPY	43.4	43.4	43.4	43.4	43.4
VOCs:					
Basis, lb/MMBtu	0.03	0.03	0.03	0.03	0.03
lb/hr	2.97	2.97	2.97	2.97	2.97
TPY	13.0	13.0	13.0	13.0	13.0
Lead:					
Basis, lb/10E+12 Btu	Neg.	Neg.	Neg.	Neg.	Neg.
lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
TPY	0.000	0.000	0.000	0.000	0.000

Note: Additional 5 lb/hr of PM are emitted due to heat stable salts from amine absorber.
Additional 14.7 lb/hr of VOCs are emitted due to monoethanolamine (as carbon) from amine absorber.

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Table A-25. Maximum Other Regulated Pollutant Emissions for CO2 Plant (Without Contribution from CT)

Pollutant	Units	Duct Burner Data with Gas Turbine on Oil at Ambient Temperature				
		20of	40oF	59oF	80oF	100oF
A		B	C	D	E	F
Arsenic	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Beryllium	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Mercury	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fluoride	lb/10E+12 Btu (2)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Sulfuric Acid Mist	% of SO2	5	5	5	5	5
	lb/hr	2.40E-02	2.40E-02	2.40E-02	2.40E-02	2.40E-02
	TPY	1.05E-01	1.05E-01	1.05E-01	1.05E-01	1.05E-01

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Table A-26. Maximum Non-Regulated Pollutant Emissions for CO2 Plant (Without Contribution from CT)

Pollutant	Units	Duct Burner Data with Gas Turbine on Oil at Ambient Temperature				
		20oF	40oF	59oF	80oF	100oF
A		B	C	D	E	F
Manganese	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Nickel	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Cadmium	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chromium	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Copper	lb/10E+12 Btu (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Vanadium	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Selenium	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Polyorganic Matter	pg/J (1)	0.48	0.48	0.48	0.48	0.48
	lb/hr	1.10E-04	1.10E-04	1.10E-04	1.10E-04	1.10E-04
	TPY	4.84E-04	4.84E-04	4.84E-04	4.84E-04	4.84E-04
Formaldehyde	lb/10E+12 Btu (1)	38	38	38	38	38
	lb/hr	3.76E-03	3.76E-03	3.76E-03	3.76E-03	3.76E-03
	TPY	1.65E-02	1.65E-02	1.65E-02	1.65E-02	1.65E-02

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Table A-27. Maximum Emissions for Additional Non-Regulated Pollutant for CO2 Plant (Without Contribution from CT)

Pollutant		Gas Turbine No.2 Oil 20oF	Gas Turbine No.2 Oil 40oF	Gas Turbine No.2 Oil 59oF	Gas Turbine No.2 Oil 80oF	Gas Turbine No.2 Oil 100oF
A		B	C	D	E	F
Antimony	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Barium	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Colbalt	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Zinc	pg/J (1)	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Chlorine	ppm	Neg.	Neg.	Neg.	Neg.	Neg.
	lb/hr	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	TPY	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Example Calculations

MULBERRY COGENERATION PROJECT

EXAMPLE CALCULATIONS - 20°F CONDITIONS

(On Distillate Oil; All Other Calculations on Spreadsheet are Identical.)

Table A-1: (Note: all other data not calculated but supplied by Manufacturer)

Heat Input (10^6 Btu/hr):

Power (kW) x Heat Rate (10^6 Btu/kWh)

95,860 x 10,760/10^6 = 1,031.5 x 10^6 Btu/hr

Fuel Oil (lb/hr):

Heat Input (10^6 Btu/hr) + Fuel Heat Content (Btu/lb)

1,031.5 x 10^6 + 18,550 = 55,604 lb/hr

Volume Flow (acfm) - See Note A:

V = mRT/PM

2,605,000 lb/hr x 1,545 x (984°F + 460°R) + (28.59 x 2,116.8 lb/ft^2)

+ 60(min/hr)

= 1,600,590 acfm

Volume Flow (scfm) - See Note A:

Same as volume flow (acfm) except adjusted for standard temperature of 68°F

2,605,000 lb/hr x 1,545 x (68°F + 460°R) + (28.59 x 2,116.8) + 60

= 585,257 scfm

Volume Flow from HRSG (acfm):

CT Exhaust adjusted for temperature

1,600,590 (acfm) x (220°F + 460°R) ÷ (984°F + 460°R)

= 753,740 acfm

Velocity (ft/sec):

Volume Flow (ft^3/min) ÷ Area (ft^2) ÷ 60 sec/min

753,740 ft^3/min ÷ 60 ÷ (15.0^2 ÷ 4 x 3.14159)

= 71.1 ft/sec

<u>Table A-2</u>:

Emissions in tons per year; example for particulate:

15 lb/hr x 8,760 hr/yr ÷ 2,000 lb/ton

= 65.7 ton/yr

SO_2 Emissions--Oil (lb/hr)

55,604.0 lb/hr x 0.001 lb S/lb x 2 lb SO_2/lb S x 0.95 (emitted as SO_2)

= 105.65 lb/hr

SO_2 Emissions--Natural Gas (20°F) (lb/hr):

1,013,429 cf/hr x 1 gr ÷ 7,000 gr/lb x 2 lb SO_2/lb S ÷ 100 cf

= 2.9 lb/hr

NO_x Emissions (lb/hr) - See Note B:

42 ppm x [20.9 + 5.9 (1 - 7.53/100) - 13.22] x 2,116.8 lb/ft^2 x 1,600,590 ft^3/min

x 46 (molecular wgt NO_2) x 60 min/hr + [1,545 x (984°F + 460°R) x 10^6 (adjust for ppm)]

= 182.2 lb/hr

CO Emissions (lb/hr) - See Note C:

35 ppm x (1 - 7.53/100) x 1,600,590 acfm x 2,116.8 lb/ft^2 x 28 (molecular wgt. of carbon)

x 60 min/hr + (1,545 x (984 + 460) x 10^6)

= 82.6 lb/hr

VOC Emissions (lb/hr) - See Note C:

10 ppm x (1-7.53/100) x 1,600,590 acfm x 2,116.8 lb/ft^2 x 12 (molecular wgt. of carbon)

x 60 min/hr + (1,545 x (984 + 460) x 10^6)

= 10.11 lb/hr

Lead Emissions (lb/hr):

8.9 lb/10^{12} Btu x 1,031.5 x 10^6 Btu/hr = 9.18 x 10^{-3} lb/hr

Table A-3:

H_2SO_4 Mist Emissions (lb/hr):

Based on 5 percent of sulfur converted to acid mist

55,604 lb/hr x 0.001 lb S/lb x 3.06 lb H_2SO_4/lb 5 x 0.05 (converted)

= 8.51 lb/hr

Tables A-4 and A-5:

EPA emission factor as noted in printout; example for manganese:

$1{,}031.55 \text{ (MMBtu)} \times 6.44 \text{ lb}/10^{12} \text{ Btu}$

$= 6.64 \times 10^{-3} \text{ lb/hr}$

NOTE A

Volume is calculated based on ideal gas law:

$$PV = mRT/M$$

where: P - pressure - 2116.8 lb/ft^2
m - mass flow of gas (lb/hr)
R - universal gas constant - 1545
M - molecular weight of gas
T - temperature (°R)

NOTE B

NO_x is calculated by correcting to 15% O_2 dry conditions using ideal gas law and moisture and O_2 conditions.

Oxygen correction:

$$V_{NOx\ (15\%)} = \frac{V_{NOx\ Dry} * 5.9}{20.9 - \%O_{2\ Dry}}$$

(From 40 CFR Part 60; Appendix A, Method 20, Equation 20-4)

$$V_{NOx\ Dry} = V_{NOx\ (15\%)}\ (20.9 - \%O_{2\ Dry})\ /\ 5.9$$

$$\%O_{2\ Dry} = \%O_{2\ Act}\ /\ (1 - \%H_2O)\ ;\ \%O_{2\ Act} = \%O_{2\ Dry}\ (1 - \%H_2O)$$

(From Method 20; Equation 20-1)

$V_{NOx\ Act} = V_{NOx\ Dry}\ (1 - \%H_2O)$; (From Method 20; Equation 20-1)

Substituting:

$$\begin{aligned} V_{NOx\ Act} &= V_{NOx\ 15\%}\ (20.9 - \%O_{2\ Dry})\ (1 - \%H_2O)\ /\ 5.9 \\ &= V_{NOx\ (15\%)}\ [20.9 - (\%O_{2\ Act}\ /\ (1 - \%H_2O))]\ (1 - \%H_2O)\ /\ 5.9 \\ &= V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2)\ /\ 5.9 \end{aligned}$$

$$m_{NOx} = \frac{PVM_{NOx}}{RT} = V_{NOx\ (15\%)}\ [20.9\ (1 - \%H_2O) - \%O_2) * P * M_{NOx}\ /\ (RT * 5.9)$$

NOTE C

Same as D except only moisture correction is used:

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

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

Emission Factors

PB89-194229

United States
Environmental Protection
Agency

Office of Air Quality
Planning And Standards
Research Triangle Park, NC 27711

EPA-450/2-89-001
April 1989

AIR

EPA

ESTIMATING AIR TOXICS EMISSIONS FROM COAL AND OIL COMBUSTION SOURCES

REPRODUCED BY
U.S. DEPARTMENT OF COMMERCE
NATIONAL TECHNICAL
INFORMATION SERVICE
SPRINGFIELD, VA 22161

TABLE 4-1. SUMMARY OF TOXIC POLLUTANT EMISSION FACTORS FOR OIL COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^{12}$ Btu) Residual Oil	Emission Factor ($lb/10^{12}$ Btu) Distillate Oil
Arsenic	19	4.2
Beryllium	4.2	2.5
Cadmium	15.7	10.5
Chromium	21	48
Copper	280	280
Lead	28[c]	8.9[d]
Mercury	3.2	3.0
Manganese	26	14
Nickel	1260	170
POM	8.4[b]	22.5
Formaldehyde	405[e]	405[e]

[a] All emission factors are uncontrolled, and are applicable to oil-fired boilers and furnaces in all combustion sectors unless otherwise noted.

[b] This value was calculated using all available residual oil data given in Table 4-35. If the upper end of the range of available data is excluded when calculating an average value (which could be used in this table), the average factor for POM from residual oil combustion becomes 4.1 $lb/10^{12}$ BTU.

[c] Applicable to utility boilers only.

[d] Applicable to industrial, commercial, and residential boilers.

[e] The formaldehyde factors are based on very limited and relatively old data. Consult Table 4-37 and accompanying discussion for more detailed information.

PB81-225559

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

TRW, Inc.
Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

1981

U.S. Department of Commerce
National Technical Information Service

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

Element	Distillate oil-fired boilers			Residual oil-fired boilers			
		Existing data			Existing data		
	Current study	Ref. 42	Ref. 43	Current study	Ref. 42	Ref. 21	Ref. 28
Aluminum (Al)	178	15	250	177	156	87	132
Arsenic (As)	3.5	1.3	1.5	1.2	9.1	18	12
Barium (Ba)	1.2	8.4	16	3.3	9.5	29	31
Calcium (Ca)	75	845	450	229	780	320	1428
Cadmium (Cd)	1.3	2.5	11	0.66	0.2	52	6.9
Cobalt (Co)	3.8	2.3	1.0	11	23	50	10
Chromium (Cr)	24	36	29	29	50	30	21
Copper (Cu)	37	205	160	10	93	64	350
Fluorine (F)	—	14	—	—	1.0	2.7	149
Iron (Fe)	363	545	140	83	379	411	453
Mercury (Hg)	—	1.7	1.2	—	1.9	0.9	1.5
Potassium (K)	85	60	230	261	213	777	392
Lithium (Li)	0.5	1.5	1.2	1.1	1.0	1.4	1.7
Magnesium (Mg)	42	40	210	24	111	297	2384
Nickel (Ni)	255	112	290	728	804	964	433
Lead (Pb)	24	48	42	2	7	80	34
Antimony (Sb)	—	1.7	5.7	—	21	10	25
Silicon (Si)	735	173	—	8655	1610	400	595
Vanadium (V)	195	30	2.9	366	250	3656	714
Zinc (Zn)	42	40	110	33	46	29	66

Ave. 50.9

U.S. DEPARTMENT OF COMMERCE
National Technical Information Service

PB-296 390

Emission Assessment of Conventional Stationary Combustion Systems; Volume II Internal Combustion Sources

TRW, Inc, Redondo Beach, CA

Prepared for

Industrial Environmental Research Lab, Research Triangle Park, NC

Feb 1979

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

EPA-450/2-88-006
October 1988

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

By
Anne A. Pope
Air Quality Management Division
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

Patricia A. Cruse
Claire C. Most
Radian Corporation
Research Triangle Park, North Carolina 27709

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office Of Air And Radiation
Office Of Air Quality Planning And Standards
Research Triangle Park, North Carolina 27711

October 1988

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

APPENDIX B

MSDS FOR FS-1 SOLVENT; AND SCRUBBER VENDOR INFORMATION

265

MATERIAL SAFETY DATA SHEET

Dow Chemical U.S.A.* Midland, MI 48674 Emergency Phone: 517-636-4400

Product Code: 09900 Page: 1

PRODUCT NAME: GAS/SPEC (R) FS-1 SOLVENT

Effective Date: 05/05/89 Date Printed: 07/01/89 MSDS:001620

1. INGREDIENTS: (% w/w, unless otherwise noted)

Monoethanolamine	CAS# 000141-43-5	85%
Water	CAS# 007732-18-5	14%

This document is prepared pursuant to the OSHA Hazard Communication Standard (29 CFR 1910.1200). In addition, other substances not 'Hazardous' per this OSHA Standard may be listed. Where proprietary ingredient shows, the identity may be made available as provided in this standard.

2. PHYSICAL DATA:

BOILING POINT: 266F, 130C
VAP PRESS: .429 psia
VAP DENSITY: Not applic.
SOL. IN WATER: Complete.
SP. GRAVITY: 1.0
APPEARANCE: Clear blue liquid.
ODOR: Amine odor.
FREEZE POINT: 9F, -13C

3. FIRE AND EXPLOSION HAZARD DATA:

FLASH POINT: 208F, 98C
METHOD USED: COC
*No flash point observed up to boiling point via Seta Flash CC.

FLAMMABLE LIMITS
LFL: Not deter.
UFL: Not deter.

EXTINGUISHING MEDIA: Water fog, alcohol foam, CO2, dry chemical.

FIRE & EXPLOSION HAZARDS: Amine vapor, possible nitrogen oxide. NOX

(Continued on Page 2)

(R) Indicates a Trademark of The Dow Chemical Company

* An Operating Unit of The Dow Chemical Company

MATERIAL SAFETY DATA SHEET

Dow Chemical U.S.A.* Midland, MI 48674 Emergency Phone: 517-636-4400

Product Code: 09900 Page: 2

PRODUCT NAME: GAS/SPEC (R) FS-1 SOLVENT

Effective Date: 05/05/89 Date Printed: 07/01/89 MSDS:001620

3. FIRE AND EXPLOSION HAZARD DATA: (CONTINUED)

Water and foam may cause frothing.

FIRE-FIGHTING EQUIPMENT: Wear positive pressure self-contained breathing apparatus.

4. REACTIVITY DATA:

STABILITY: (CONDITIONS TO AVOID) Conditions incident to normal shipping and handling do not constitute a hazardous situation.

INCOMPATIBILITY: (SPECIFIC MATERIALS TO AVOID) Strong oxidizers, strong acids.

HAZARDOUS DECOMPOSITION PRODUCTS: Possible nitrogen oxides. This product should not be stored in aluminum due to possible discoloration and excessive corrosion and potential chemical reaction releasing flammable hydrogen gas.

HAZARDOUS POLYMERIZATION: Will not occur.

5. ENVIRONMENTAL AND DISPOSAL INFORMATION:

ACTION TO TAKE FOR SPILLS/LEAKS: Apply absorbent material or sand. Shovel into container.

DISPOSAL METHOD: Burn in approved incinerator in accordance with all local, state and federal regulations. Do not discharge into water environment.

(Continued on Page 3)

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MATERIAL SAFETY DATA SHEET

Dow Chemical U.S.A.* Midland, MI 48674 Emergency Phone: 517-636-4400

Product Code: 09900 Page: 3

PRODUCT NAME: GAS/SPEC (R) FS-1 SOLVENT

Effective Date: 05/05/89 Date Printed: 07/01/89 MSDS:001620

6. HEALTH HAZARD DATA:

EYE: May cause severe irritation with corneal injury which may result in permanent impairment of vision, even blindness. Vapors may irritate eyes.

SKIN CONTACT: Short single exposure may cause skin burns. Classified as DOT corrosive.

SKIN ABSORPTION: A single prolonged exposure may result in the material being absorbed in harmful amounts. The LD50 for skin absorption in rabbits is approximately 2000 mg/kg.

INGESTION: Single dose oral toxicity is low. The oral LD50 for rats is in the 1000 - 2000 mg/kg range. Ingestion may cause

gastrointestinal irritation or ulceration and burns of mouth and throat.

INHALATION: Excessive exposure may cause liver and kidney injury and irritation to upper respiratory tract.

SYSTEMIC & OTHER EFFECTS: Repeated excessive exposures may cause liver and kidney injury. Birth defects are unlikely. Exposures having no adverse effects on the mother should have no effect on the fetus. In animal studies, monoethanolamine has been shown not to interfere with reproduction. Results of in vitro ("testtube") mutagenicity tests monoethanolamine have been negative.

7. FIRST AID:

EYES: Immediate and continuous irrigation with flowing water for at least 30 minutes is imperative. Prompt medical consultation is essential.

SKIN: In case of contact, immediately flush skin with plenty of water for at least 15 minutes while removing contaminated clothing and shoes. Call a physician if irritation persists. Wash clothing before reuse. Destroy contaminated shoes and

(Continued on Page 4)
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* An Operating Unit of The Dow Chemical Company

MATERIAL SAFETY DATA SHEET

7. FIRST AID: (CONTINUED)

other leather articles.

INGESTION: Do not induce vomiting. Give large amounts of water or milk if available and transport to medical facility.

INHALATION: Remove to fresh air if effects occur. Consult a physician.

NOTE TO PHYSICIAN: The decision of whether to induce vomiting or not should be made by an attending physician. Corrosive. May cause stricture. If lavage is performed, suggest endotracheal and/or esophagoscopic control. If burn is present, treat as any thermal burn, after decontamination. No specific antidote. Supportive care. Treatment based on judgment of the physician in response to reactions of the patient.

8. HANDLING PRECAUTIONS:

EXPOSURE GUIDELINE(S): Ethanolamine: ACGIH TLV and OSHA PEL are 3 ppm TWA, 6 ppm STEL.

VENTILATION: Control airborne concentrations below the exposure guideline. Good general ventilation should be sufficient for most conditions. Local exhaust ventilation may be necessary for some operations.

RESPIRATORY PROTECTION: Atmospheric levels should be maintained below the exposure guideline. When respiratory protection is required for certain operations, use an approved air-purifying respirator.

SKIN PROTECTION: Use protective clothing impervious to this material. Selection of specific items such as gloves, boots, apron, or full-body suit will depend on operation. Safety shower should be located in immediate work area. Remove contaminated clothing immediately, wash skin area with soap and water, and launder clothing before reuse. Contaminated leather

(Continued on Page 5)

MATERIAL SAFETY DATA SHEET

Dow Chemical U.S.A.* Midland, MI 48674 Emergency Phone: 517-636-4400

Product Code: 09900 Page: 5

PRODUCT NAME: GAS/SPEC (R) FS-1 SOLVENT

Effective Date: 05/05/89 Date Printed: 07/01/89 MSDS:001620

8. HANDLING PRECAUTIONS: (CONTINUED)

items, such as shoes, belts and watchbands, should be removed and destroyed.

EYE PROTECTION: Use chemical goggles. Wear full-face respirator to prevent contact with vapors.

9. ADDITIONAL INFORMATION:

REGULATORY REQUIREMENTS:

SARA HAZARD CATEGORY: This product has been reviewed according to the EPA 'Hazard Categories' promulgated under Sections 311 and 312 of the Superfund Amendment and Reauthorization Act of 1986 (SARA Title III) and is considered, under applicable definitions, to meet the following categories:

An immediate health hazard
A delayed health hazard
A fire hazard

SPECIAL PRECAUTIONS TO BE TAKEN IN HANDLING AND STORAGE: Prevent eye and skin contact. Avoid breathing vapors. Storage in aluminum is not recommended.

MSDS STATUS: Revised Section 8.

(R) Indicates a Trademark of The Dow Chemical Company
The Information Herein Is Given In Good Faith, But No Warranty, Express Or Implied, Is Made. Consult The Dow Chemical Company For Further Information.

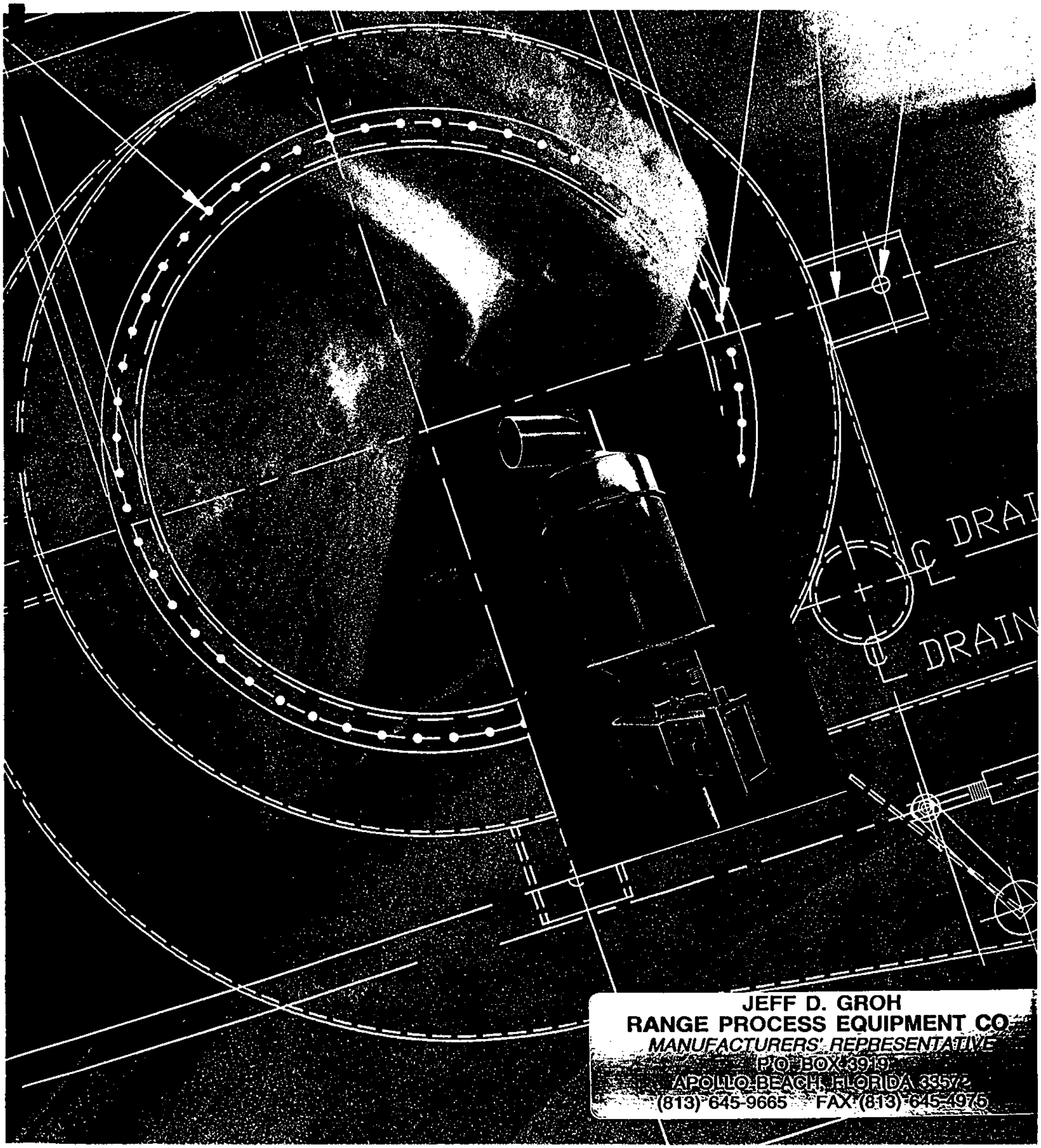
* An Operating Unit of The Dow Chemical Company

MPS BULLETIN #693S

Fisher-Klosterman, Inc.

MPS–MULTIPLE PURPOSE SCRUBBER

FISHER-KLOSTERMAN'S NEW MPS SCRUBBER SAVES SPACE, SAVES ENERGY, SAVES MONEY.



JEFF D. GROH
RANGE PROCESS EQUIPMENT CO.
MANUFACTURERS' REPRESENTATIVE
P.O. BOX 3919
APOLLO BEACH, FLORIDA 33572
(813) 645-9665 FAX (813) 645-4975

FKI PRESENTS A SINGLE UNIT THAT DOES THE JOB OF THREE

Fisher-Klosterman, Inc. (FKI), a leader in the custom design, fabrication and installation of high efficiency pollution control equipment since 1948 has recently developed a revolutionary new approach to scrubber system design that combines the superior scrubbing technologies of a venturi scrubber, a cyclonic separator and a packed tower in a single, compact, efficient unit. Of course, FKI continues to be the leader in the design and manufacturing of these components separately, but if your situation calls for the removal of the broadest range of contaminants and pollutants from a gaseous stream, the new MPS Series of multiple purpose scrubbers eliminates everything from particulates to gases without the cumbersome need for three separate and expensive components. One unit does it all.

Now a single unit can cleanse

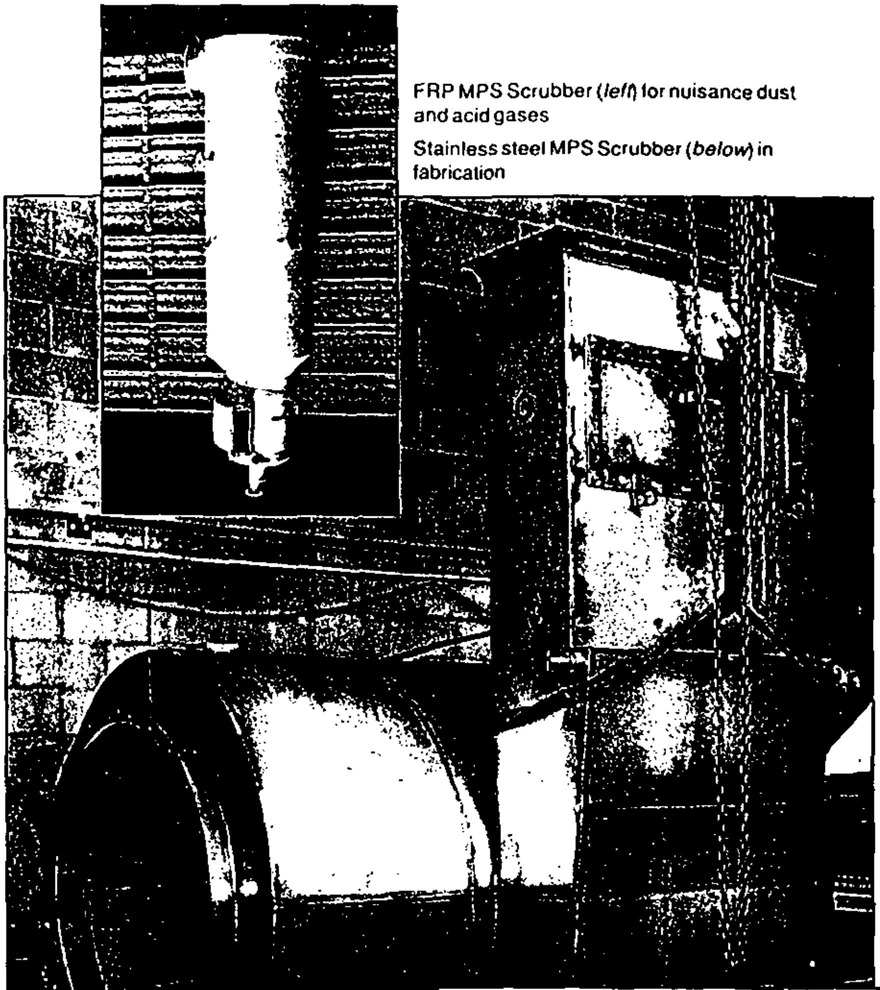
PARTICULATE

- Ash
- Grit
- Plastics
- Chemicals
- Pharmaceuticals
- Sand
- Minerals
- Metals

FUMES

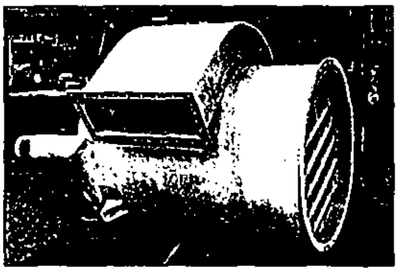
- HF
- Acids
- Formaldehydes
- HCL
- SO_x
- NO_x
- NH_3

easily, efficiently and economically.

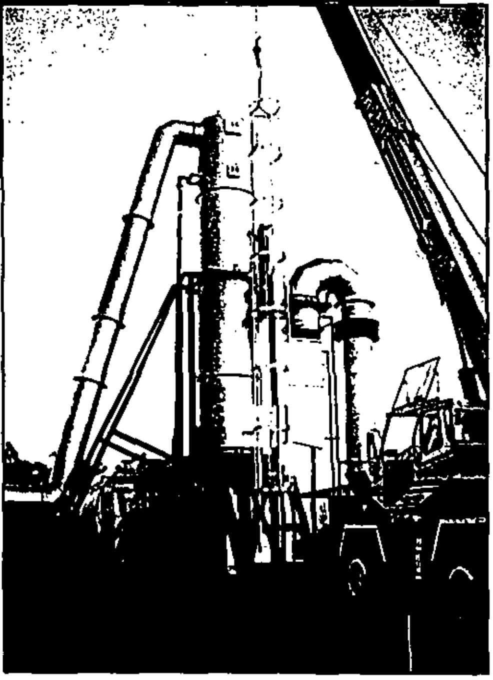


FRP MPS Scrubber (*left*) for nuisance dust and acid gases

Stainless steel MPS Scrubber (*below*) in fabrication

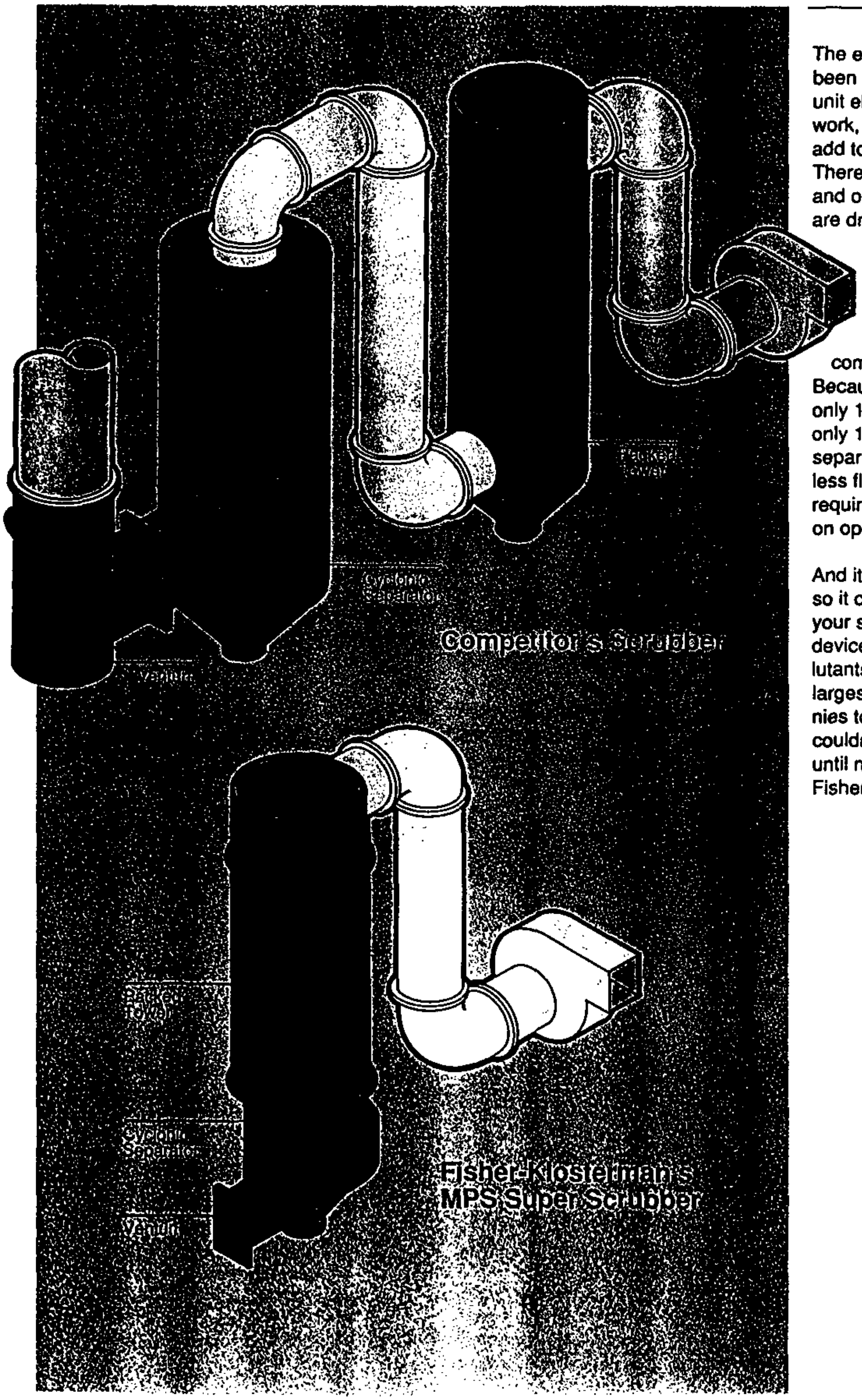


FRP MPS Scrubber (*above*) in fabrication



MPS Scrubber (*right*) being installed on hazardous waste incineration system (on-site at major oil spill)

. . . AND DOES IT FOR LESS!



The entire scrubbing operation has been combined into a single compact unit eliminating much of the concrete work, steel fabrication and piping that add to the cost of other systems. Therefore, the equipment, installation and operating costs of the MPS Series are dramatically reduced.

Plus, thanks to a design breakthrough in the cyclonic separator, the MPS Series scrubbers are significantly smaller than any comparable, three-unit system. Because the cyclone chamber has only 1/2 the cross-sectional area and only 1/3 the height of other cyclonic separators, the whole design takes up less floor space, uses less energy, requires less maintenance and saves on operating costs.

And it's a Fisher-Klosterman system, so it can be custom designed to meet your specific needs. It's the ideal device for the removal of multiple pollutants at all sorts of job sites, from the largest chemical and utilities companies to more modest operations that couldn't afford such a complete system until now. It's the MPS Series from Fisher-Klosterman.

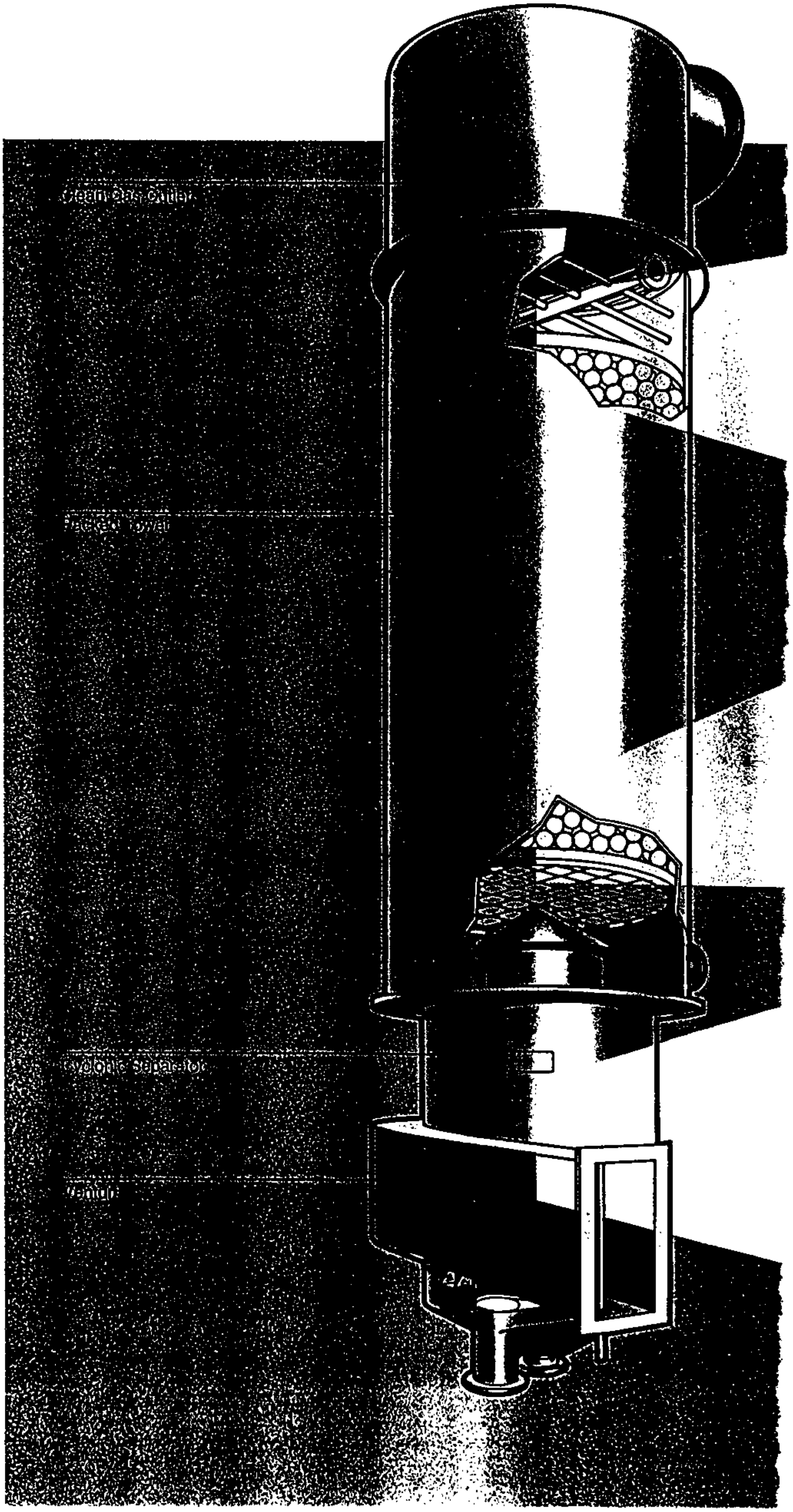
HERE'S HOW IT WORKS

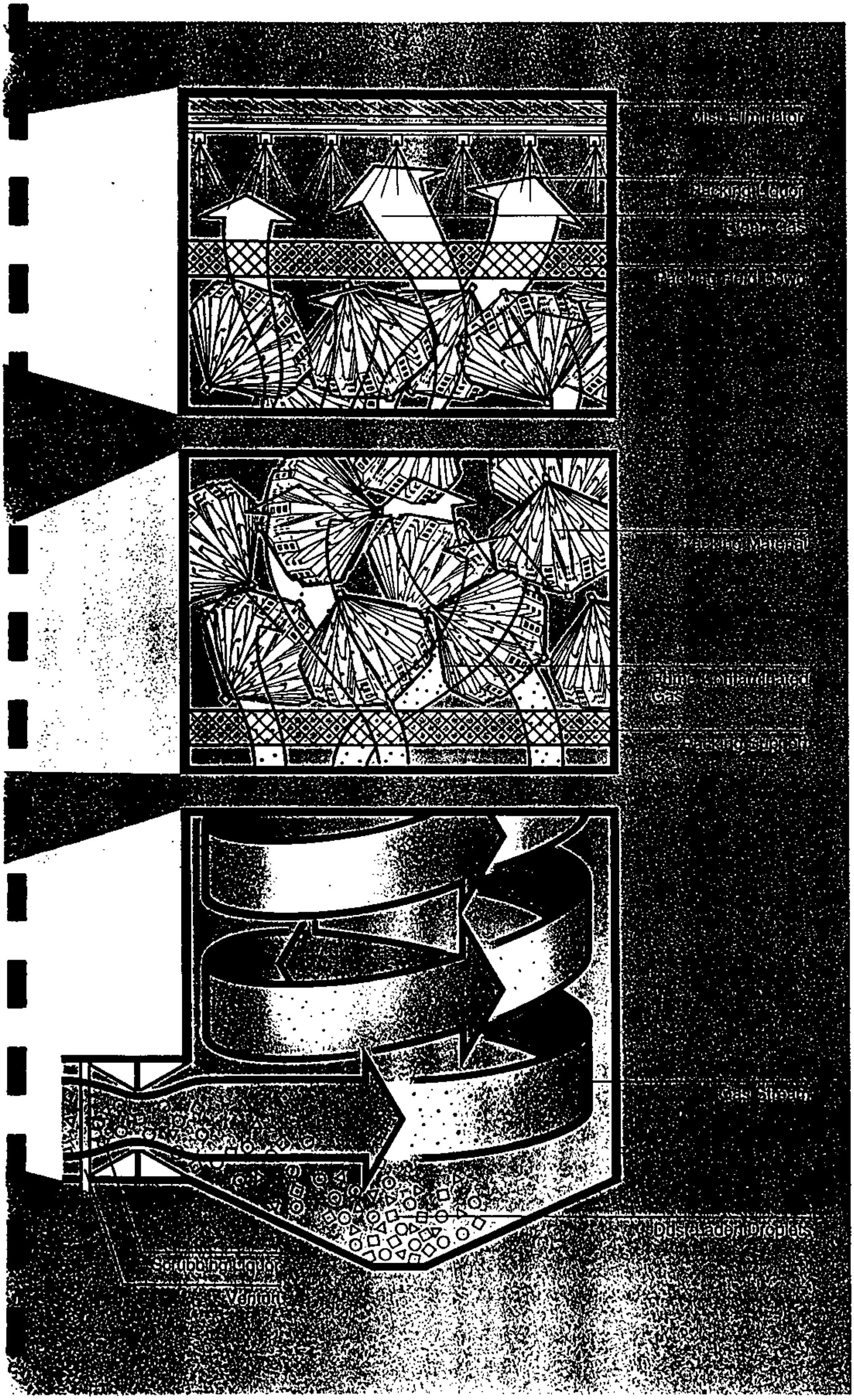
Stage One: The Venturi Scrubber

The first step in eliminating multiple pollutants from a gaseous stream is to remove the dust and other particulate from the gas. This is done by accelerating the dust-laden gas through a narrow-throat venturi, where liquid is injected into the stream. The resulting turbulence causes the liquid droplets to collide with the particles. These particles adhere to the liquid, so that they may be effectively separated from the gas stream in the next stage of the process.

Stage Two: The Cyclonic Separator

This stage of the process utilizes a high speed vortex to separate the particle-laden liquid droplets from the gaseous stream. The force of the vortex sends the heavier droplets out against the walls of the cyclone chamber, where they form a liquid film that flows down and out of the chamber through two drains. At the same time the lighter gas is sent out the top of the chamber and on to the third stage of the process.





Stage Three: The Packed Tower

Also known as a packed bed scrubber, the packed tower removes any gaseous pollutant from the stream by contacting the contaminated gas with a scrubbing liquor that absorbs the contaminant into the liquid film. In order to increase the total surface area of the liquor so that it absorbs more contaminant gas, a packing material fills the tower. The gas is forced to work its way slowly up a tortuous route to the top of the tower, all the while contacting the scrubbing liquor on its way down. The result is a clean gas stream exiting the system free of particulate and gaseous contaminants.

The packing material is the secret to a truly efficient packed tower. Packing materials are quite diverse with many different shapes, sizes and materials of construction. Factors to be considered when choosing a packing are efficiency of absorption, chemical compatibility with the contaminant gas and scrubbing liquor, ease of maintenance and cost. Engineers at FKI will select the packing best suited to your specific needs.

THE FISHER-KLOSTERMAN STORY: PRODUCT INNOVATION, SERVICE AND PERFORMANCE

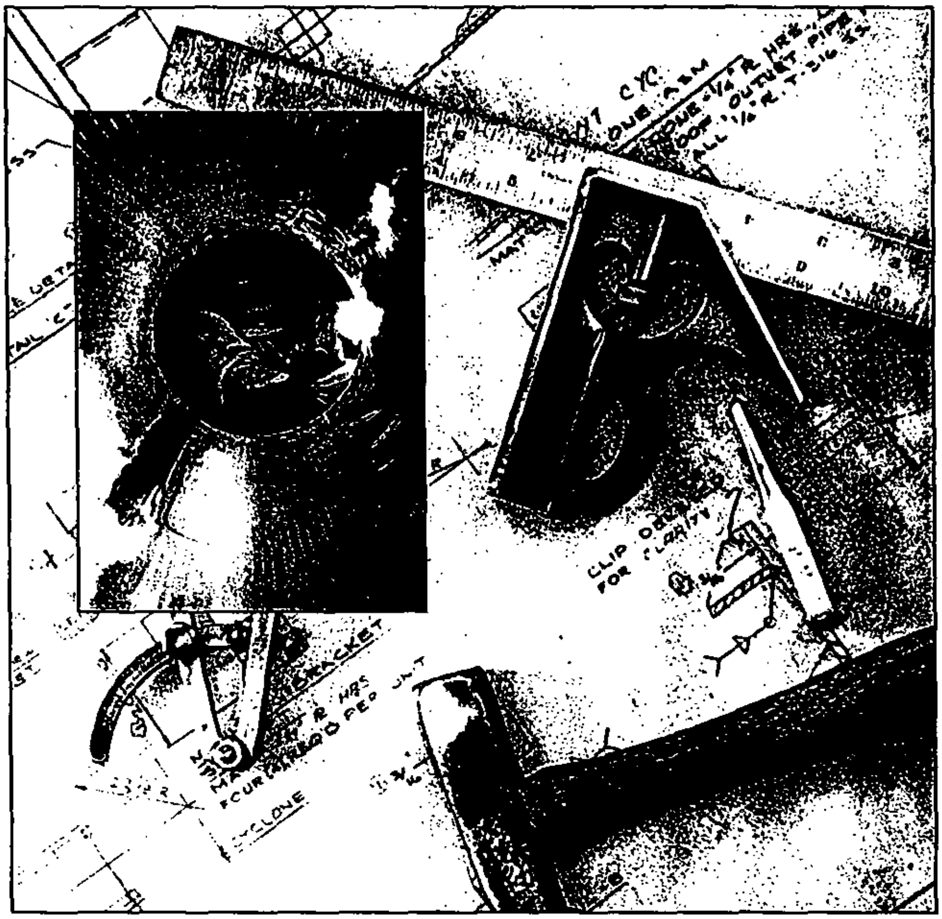
Particulate pollution takes many forms, and no two applications are just alike. That's why plant operators and engineers often turn to Fisher-Klosterman. We've built a special niche in our industry as an experienced, innovative supplier of pollution control equipment for custom applications.

We're not a new firm — we've been custom designing and fabricating pollution control equipment since 1948. Most jobs involve the following steps:

1. First, we help identify and quantify your needs through test sampling and laboratory analysis.
2. Next, we make equipment recommendations and provide cost estimates.
3. Then we custom design and fabricate the system.
4. We can provide field and/or engineering supervision, turn-key installation, system start-up, calibration and check out as well. Fisher-Klosterman systems and equipment are available for a variety of applications including:

- in-plant environmental improvement
- air pollution control
- pneumatic conveying
- product classification
- product recovery
- waste or scrap disposal
- processing equipment

All of our services and products are backed by an unequivocal warranty covering quality of materials and workmanship, and performance according to specifications.



TELL US ABOUT YOUR NEEDS

We can help you select the right scrubber for your application — that's one of our customer services. But we will need help from you. Please provide us with the following information:

Gas conditions at collector inlet:

1. Volume (ACFM)____________________
2. Pressure (PSIG or PSIA)____________________
3. Temperature given in °F or °C____________________
4. Moisture content — specify by weight or volume____________________
5. Attach gas analysis if other than air — specify by weight or by volume____________________

Dust conditions at inlet:

1. Identity or origin ____________________
2. Particulate specific gravity or density ____________________
3. Bulk density in lbs./cu. ft. ____________________
4. Type of material: corrosive, abrasive, sticky, explosive, toxic ____________________
5. Dust load (lb./hr. or grain/ACF) ____________________
6. Attached aerodynamic particle size distribution ____________________
7. Method of particle size distribution determination ____________________

Collector information:

1. Required collection efficiency____________________ (List by contaminant)
2. Fan on inlet or outlet side of collector ____________________
3. Maximum allowable pressure drop given in " w.c. ____________________
4. Materials of construction ____________________
5. Design pressure ____________________
6. Physical space/size restrictions ____________________

If you are unable to determine the aerodynamic particle size distribution (APSD), we will be glad to analyze a sample for you. A stack test may be required if you have difficulty collecting the above data. This test measures gas properties, the dust loading and APSD at the scrubber's installation point.

Fisher-Klosterman, Inc.
P. O. Box 11190
Louisville, KY 40251-0190
Phone: (502) 776-1505
Fax: (502) 774-4157

IF YOU'D LIKE HELP IN DETERMINING YOUR NEEDS OR MORE INFORMATION ABOUT OUR PRODUCTS, WRITE OR GIVE US A CALL. THERE'S A FISHER-KLOSTERMAN REPRESENTATIVE NEAR YOU.

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274-2620
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831-2142
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Buenos Aires, Argentina
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Fisher-Klosterman Regional Office
Bogota, Colombia
57-1-215-3280

VENEZUELA
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Caracas, Venezuela
58-2-564-0178 / 0668

INDIA

Ushamil Pvt. Ltd.
New Delhi
91-11-643-1404

W.W. Sly Manufactures Two Types of Scrubbers...

Impinjet®

Impinjet® Scrubbers Cool, Clean and Absorb Odors, Vapors and Gases. The Impinjet Scrubber removes materials such as odors, vapors or gases suspended in gas streams, as well as larger particles.

Rugged and uncomplicated in design, Impinjet Scrubbers offer the highest efficiency available in modern gas scrubbers removing gases, odors and vapors. Engineered to provide *minimum pressure drop*, the scrubber operates with resultant lower power requirements. Attractive benefits follow—thoroughly efficient gas cleaning and cooling with reduced operating costs.

Efficiencies in excess of 99% can be realized on most types of dust or gases. Impinjet Scrubber capacities range from 200 to over 1,000,000 CFM. Depending upon application, water requirements vary from less than 1½ GPM per 1,000 CFM to a typical 3 GPM per 1,000 CFM.

Unique flexibility is furnished by Impinjet Scrubbers. Made with the future in mind, additional stages can be added to existing installations to handle tomorrow's efficiency requirements—*without increasing liquid consumption*. No need to buy complete new units.

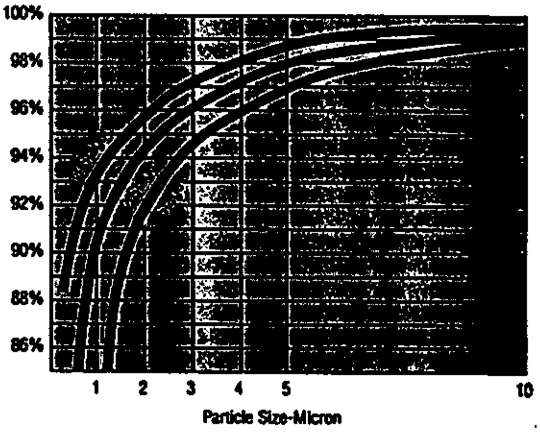
Venturi

Venturi Scrubbers Efficiently Collect Fine Particulate and Liquid Mists

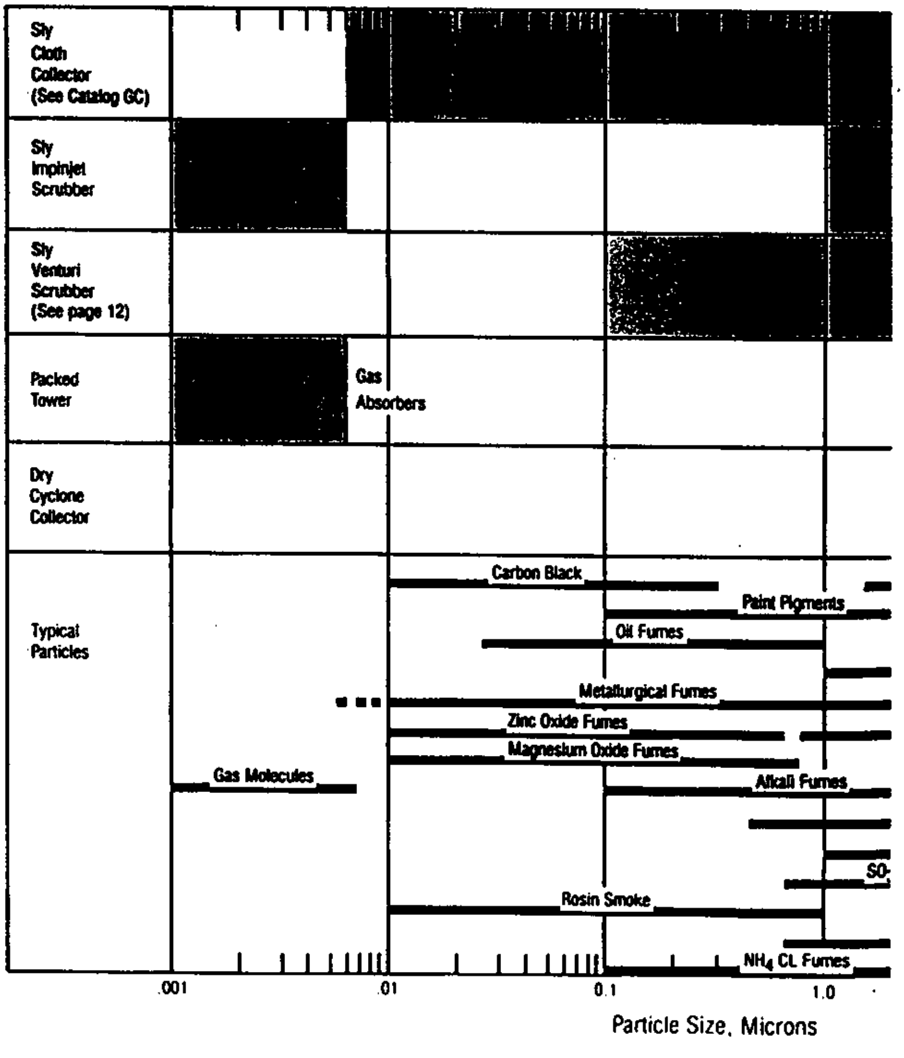
The Sly Venturi Scrubber uses the differential between high velocity gases and free-flowing water to create droplets which entrap contaminants, hold them in suspension and deliver them as a highly concentrated slurry. The Sly Venturi Scrubber offers more advantages in separating and recovering liquid mists and ultra-fine particulate than other gas cleaning methods.

See pages 12-15 for more Venturi information.

Standard Impinjet Efficiency@ Pressure Drop of 1-½" per Stage



Selecting the Right Collector



Advantages of the Sly Impinjet®

1.) **High absorption efficiency for gases, odors and vapors.** Experts agree that plate towers have the ability of removing gaseous pollutants to any desired concentration if a sufficient number of plates is used. This means high mass transfer rates can be achieved. Plate columns are preferable to packed towers whenever a large number of transfer units or theoretical stages are required.

2.) **High collection efficiency for particles 1 micron in size or larger.**

3.) These high efficiencies are achieved at a low pressure drop.

4.) Both particle collection and absorption of gases, odors, vapors, etc. can be done at the same time.

5.) Multiple stages can be provided.

6.) Can be built in large sizes. Available in standard sizes.

7.) No moving parts to maintain.

8.) Extensive experience with many applications available.

9.) Need less scrubbing fluid than most other scrubbers, but can handle higher liquid rates than packed towers.

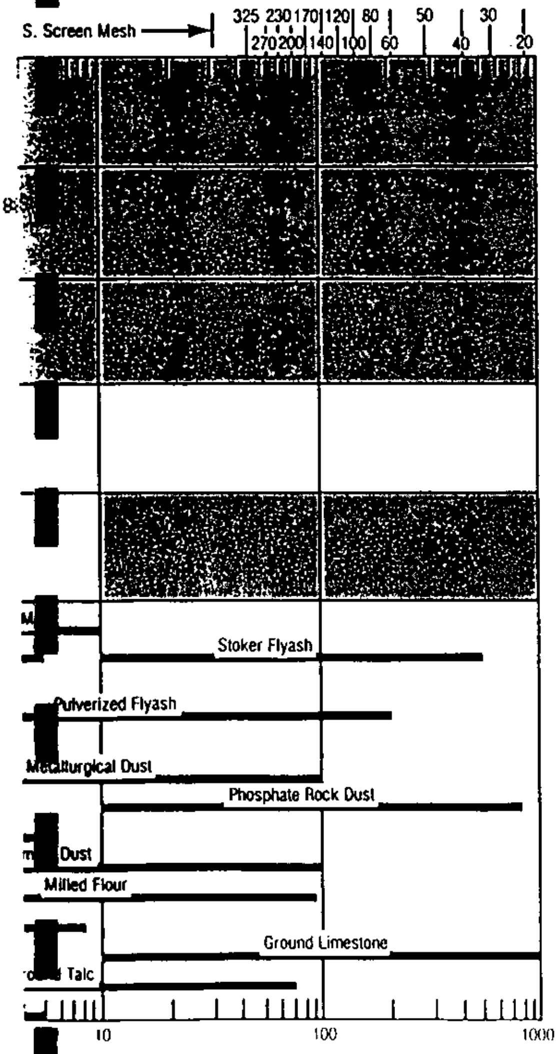
10.) They can handle volume changes better than packed towers.

11.) They can handle high temperatures and temperature fluctuations. Cooling coils can be installed if heat of solution requires it.

12.) Cannot "channel" like packed towers.

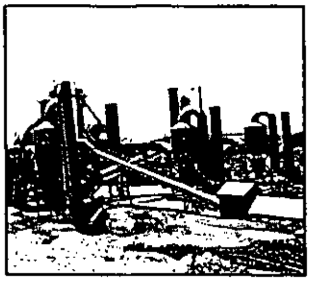
13.) One plate is the equivalent of up to 8 feet of packing.

Single stage No. 180 Impinjet Scrubber fabricated from 304 stainless steel, vents kiln handling lead and zinc ore. The unit operates at 20,000 CFM and a temperature of 200°F. Liquid consumption requirement is 60 GPM.



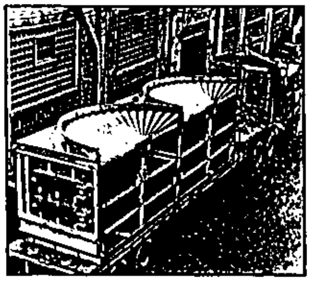
Cooling and Condensing

For these applications (heat transfer) thermal efficiencies of approximately 90% can be achieved. The outlet gas can be cooled to less than 5°F above the temperature of the incoming liquid. Often solvents such as alcohols, pentane, hexane, acetone, ethylene glycol, chloroform, etc. are recovered from inert gas streams such as nitrogen or carbon dioxide. Chilled solvent is used as direct contact condensing liquid and removes the heat from the gas stream as it gains heat. Scrubbers also recover waste heat. Heat from dryers and other processes that would normally be lost out of exhaust stacks is used to heat water being fed to the scrubber almost to the wet bulb temperature of the inlet gas. For cooling and condensing and for heat recovery the scrubber is capable of handling liquid rates of over 30 GPM per 1,000 CFM instead of the usual 2 to 3 GPM per 1,000 CFM.



Single stage units can be used wherever high efficiency at moderate temperatures is required. One stage (plate or tray) will do a thorough cleaning and cooling job, meeting codes on many applications.

Multi-stage units give a wide range of usefulness on high temperature applications, chemical absorption and where extremely high efficiency is needed.



Two stage Impinjet being shipped to site at a fluid bed coal dryer. 160,000 CFM enter at 150°. This is one of nineteen Sly Scrubbers sold to the same coal company.

Operating Principles

The gas passes up through the openings in the perforated plates (trays) which hold a bed of liquid. The secret is in the scrubber's design which uses an impingement baffle above each individual hole.

It is a modified sieve plate scrubber using flooded perforated plates with an impingement baffle over each hole. Over 4,750 holes/sq. ft.

Gas velocities of 60 to 75 feet/second through the holes result in thousands of jets which atomize the liquid into droplets on the order of 100 microns/diameter to clean the contaminated gas. This entraps the particles in the scrubbing liquid. Each jet aspirates liquid from the blanket of scrubbing fluid and results in a wetted target surface on the baffle which is located just above the point of maximum velocity (vena contracta). This intimate gas liquid contact results in the maximum collection efficiency for particles and droplets as well as absorption (mass transfer) of gases, odors and vapors. When used for absorption, low outlet emissions can be achieved since at the top stage the fresh incoming scrubbing liquid contacts the air with the lowest concentration of contaminant after it passes through the lower stage or stages. Like all plate or tray type scrubbers, the Sly Impinjet Gas Scrubber is able to reduce gaseous pollutants to any desired concentration if a sufficient number of plate stages is used.

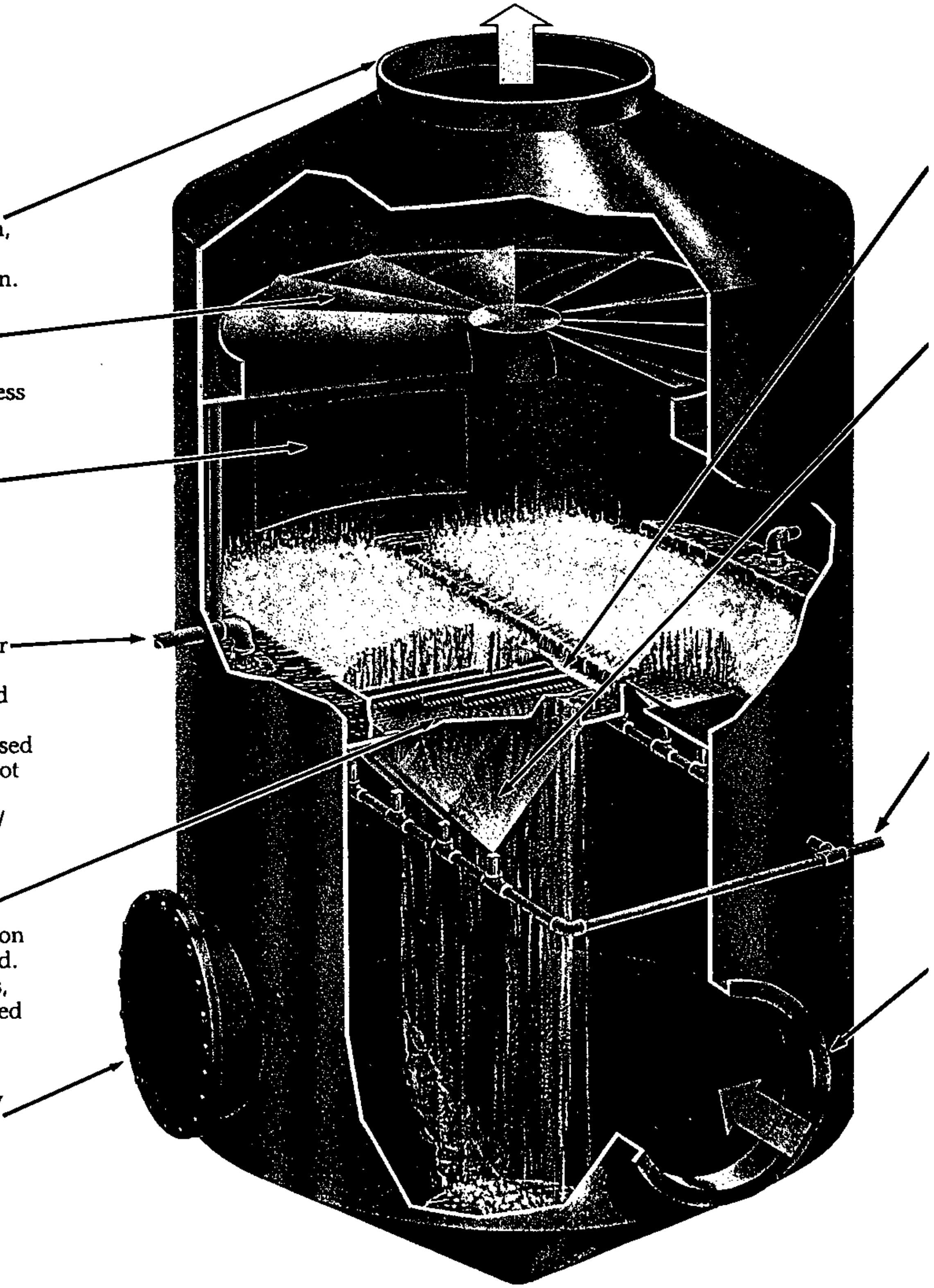
It is the tiny droplets, not the wetted baffles which are effective in collecting. Based on inertial impaction at 75 ft/sec for 1 micron sized particles with a specific gravity of 2.7, the efficiency of the 100 micron droplets is 80% but only 3% for the wetted target.

It is important to remember that the intimate contact of the gases and fine mist at the impingement baffle plates (trays, stages) results in very efficient a) cooling, b) absorption of gases, odors and vapors and c) collection of particles and mists.

An important feature of the particular design of scrubber is its freedom from pluggage in spite of the small holes. The continuous violent agitation of the blanket of scrubbing fluid prevents settling of particles and flushes them away. Sly's extensive experience with substances like clay prove this.

How The Impinjet® Operates

1. Scrubber Outlet - to fan, if suction system. To exhaust stack, if blow-in.
2. Fixed Blade Mist Eliminator - assures droplet-free air to process or atmosphere.
3. Access Door - permits inspection of plates. Peepholes and quick opening doors are available as options.
4. Liquid Supply and Weir (dam) - adjustable weir provides uniform liquid flow to plates. Recirculated slurries may be used if concentration does not exceed 10% by weight. Average flow 1-2 GPM/ 1000 CFM.
5. Impingement Baffle Plates - create interaction of gas stream and liquid. Additional plates (trays, stages) provide increased efficiency.
6. Access Door - for spray inspection and maintenance.



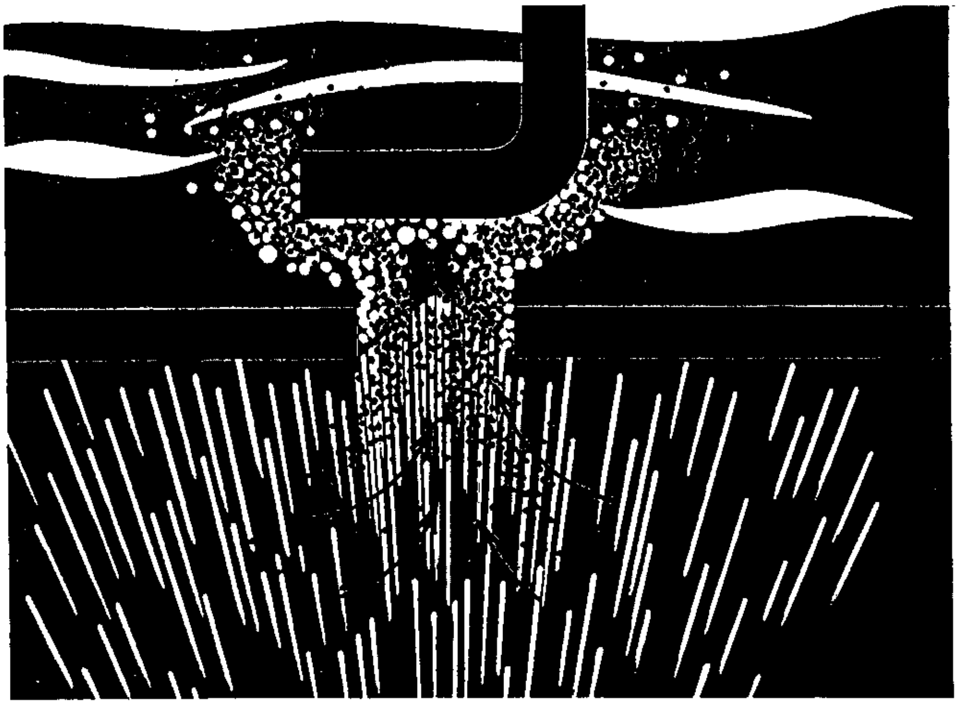
Impingement Baffle Plate Assures Thorough Scrubbing

7. Plate Discharge and Seal Drain - directs slurry to bottom of scrubber for removal. Non-clogging seal prevents short circuiting of gas.

8. Spray Section - for cooling and entrapment of larger particles. Spray washes under side of plate and walls to prevent material build-up. Sprays are non-clogging. Recirculated liquid may be used if particle sizes contained are below 3/32 inches.

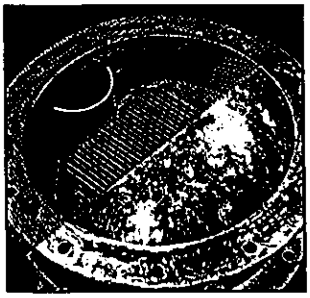
9. Liquid Spray Inlet - uses approximately 0.5 to 1 GPM/1,000 CFM at 20 PSIG. Liquid consumption is greater if cooling of gas is required. (Combining liquid utilized by liquid supply (No. 4) and spray inlet (No. 9) provides total liquid flow.)

10. Gas Inlet - if suction job, from process; if pressure, from blow-in fan.



Impinjet is actually two scrubbers in one. The spray section cools and humidifies entering gas while simultaneously removing larger particulate matter. In addition, the under-plate spray action keeps the plate and walls clean and prevents build-up.

Actual scrubbing is accomplished by the jet action of gas in the liquid, produced by the uniquely designed impingement baffle plate. This turbulent effect assures thorough wetting of particles. Impingement baffle plates are generally made of various stainless steels, but can also be fabricated from plastics and other materials.



Venturi Effect results in turbulent interaction of liquid and dirt laden gas flowing through perforated plate and striking wetted impingement baffle grid. (Each hole has an individual impingement surface). Minute liquid droplets are formed which entrap suspended matter in gas. Dirt carrying droplets mix with water flowing across baffles for ultimate disposal through drain. Cleaned gas passes into mist eliminator for return to process or atmosphere

Two factors create the high efficiency found in our impingement plate design:

1. the formation of a great number of minute droplets of liquid at plate orifices, and
2. the high velocity, relative to the minute droplets, at which dust particles enter the orifices. (Few scrubbers have both high relative velocities and form minute droplets which in *combination* give the highest efficiency possible at any given pressure drop.)

Greater particle collection efficiency is attainable by increasing relative velocity (higher pressure drop). The net effect is an improvement in the relative velocity of dust and liquid droplets, intensifying the entrapment of dust particles by the liquid medium. This same principle is highly effective in gas cooling wherein high relative velocity and small droplet size assures intimate contact.

Impinjet® Scrubber Selection

For standard applications, Impinjet Scrubbers as shown in the chart below, are furnished with stainless steel type 304 baffle plates; 3/16-inch mild steel shell; all internal sprays and piping; mist eliminator; inspection doors and inlet and outlet flanges.

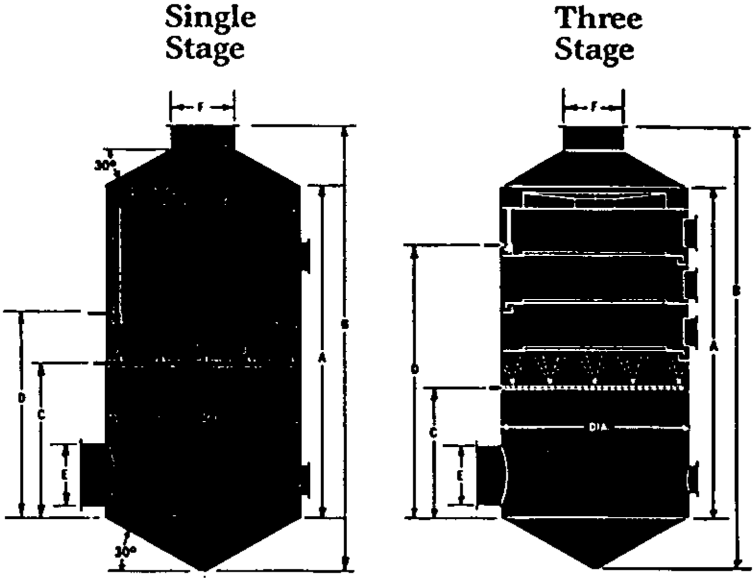
Coated mild steel, stainless steel, PVC, Polypropylene and FRP are all available for special chemical applications *(see chart on page 7)*.

Complete or partial; alloy construction or capacities larger than tabulated below are engineered to your specific requirements. Consult your Sly representative or directly contact the factory.

Volume Correction

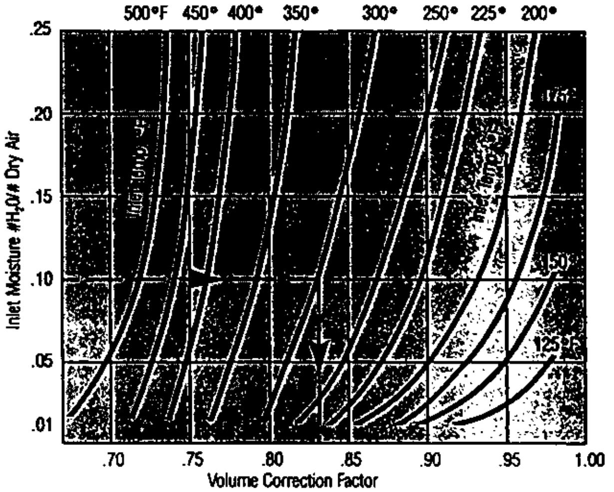
Converting inlet volume to outlet volume is necessary in sizing scrubber capacities. Inlet volume and inlet moisture content are either known or must be assumed from the application. The chart reflects the Volume Correction Factor needed to determine outlet volume by reading down from the intersection of inlet moisture and its temperature in °F. Inlet Volume x Correction Factor = Outlet Volume.

> Example: Given Inlet Volume at 6000 CFM and Inlet Moisture at 0.10 #H_2O/#Dry Air @ 300°F., chart shows Correction Factor of 0.83. Inlet Volume, 6000 CFM x Correction Factor, 0.83 = Outlet Volume of 4980 CFM.
>
> Size Impinjet Scrubber for 4980 CFM. *In this case, you would select a 4'0" diameter scrubber.*


Single Stage
Three Stage

Volume Correction

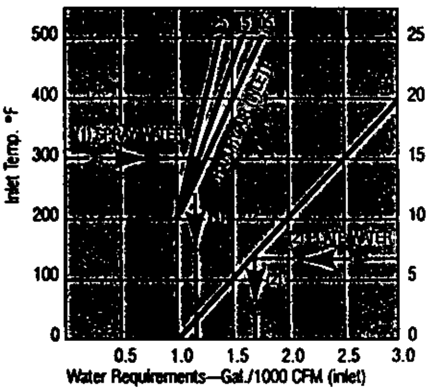
(use to determine outlet volume)



OUTLET VOLUME (CFM) Normal Capy 420 FPM	Max Capy 500 FPM	Dia	Plate Water Inlet I.P.S. Inches	Spray Water Inlet I.P.S. Inches	Bottom Drain I.P.S. Inches	Impinjet Number	Single Stage Dimensions Straight Side A	Over-All Height B	Spray Water Inlet C	Plate Water Inlet D	Inlet Flange Dia. E	Outlet Flange Dia. F
740	885	1'6"	½	½	1	115	5'4"	6' 4"	1' 3"	3' 3"	6"	7"
1350	1550	2'0"	¾	½	1	120	5'6"	6' 9"	1' 5"	3' 5"	8"	8"
2100	2450	2'6"	1	¾	1¼	125	5'9"	7' 2"	1' 7"	3' 7"	10"	11"
3000	3500	3'0"	1	¾	1¼	130	6'0"	7' 8"	1' 9"	3' 9"	1' 0"	1' 1"
4050	4800	3'6"	1¼	1	1½	135	6'3"	8' 2"	1'11"	3'11"	1' 2"	1' 3"
5300	6250	4'0"	1¼	1	1½	140	6'6"	8' 7"	2' 1"	4' 1"	1' 4"	1' 5"
6700	7950	4'6"	1¼	1	1½	145	6'9"	9' 1"	2' 3"	4' 3"	1' 6"	1' 7"
8250	9800	5'0"	1½	1¼	2	150	7'3"	9'10"	2' 3"	4' 3"	1' 7"	1' 9"
10000	11850	5'6"	1½	1¼	2	155	7'6"	10' 3"	2' 5"	4' 5"	1' 9"	1'11"
11900	14100	6'0"	1½	1¼	2	160	7'9"	10' 9"	2' 8"	4' 8"	2' 0"	2' 2"
13950	16550	6'6"	2	1¼	2½	165	8'0"	11' 3"	2'10"	4'10"	2' 2"	2' 4"
16200	19200	7'0"	2	1½	2½	170	8'3"	11'10"	3' 1"	5' 1"	2' 4"	2' 6"
18600	22050	7'6"	2	1½	2½	175	8'6"	12' 3"	3' 3"	5' 3"	2' 6"	2' 8"
21150	25100	8'0"	2	1½	2½	180	9'3"	13' 3"	3' 6"	5' 6"	2' 8"	2'10"
23850	28350	8'6"	2½	2	3	185	9'9"	13'11"	4' 0"	6' 0"	2'10"	3' 0"
26750	31800	9'0"	2½	2	3	190	10'0"	14' 5"	4' 3"	6' 3"	3' 0"	3' 2"
29800	35400	9'6"	2½	2	3	195	10'6"	15' 2"	4' 8"	6' 8"	3' 2"	3' 4"
33000	39250	10'0"	2½	2	3	1100	10'9"	15' 8"	4'11"	6'11"	3'0"x3' 2"	3' 7"
36400	43250	10'6"	2½	2	3	1105	11'0"	16' 1"	5' 2"	7' 2"	3'0"x3' 6"	3' 9"
39950	47500	11'0"	3	2	4	1110	11'6"	16'10"	5' 6"	7' 6"	3'0"x3'10"	3'11"
43650	51900	11'6"	3	2	4	1115	13'0"	18' 7"	6' 0"	8' 0"	3'0"x4' 2"	4' 1"
47550	56500	12'0"	3	2½	4	1120	13'3"	19' 1"	6' 3"	8' 3"	3'0"x4' 6"	4' 4"
51550	61350	12'6"	3	2½	4	1125	13'6"	19' 7"	6' 6"	8' 6"	3'0"x5' 0"	4' 6"
55750	66500	13'0"	3	2½	4	1130	13'9"	20' 1"	6' 9"	8' 9"	3'0"x5' 4"	4' 8"
60150	71550	13'6"	3	2½	4	1135	14'0"	20' 6"	7' 0"	9' 0"	3'0"x5'10"	4'10"
64700	76950	14'0"	4	2½	4	1140	14'3"	21' 0"	7' 3"	9' 3"	3'0"x6' 4"	5' 0"

Water Requirements

(Fresh or Recirculated)



To use chart, the following inlet conditions must be known or assumed—temperature, moisture content, dust load and volume.

(1) Spray Water Requirements (at 20 psig) - apply inlet temperature and inlet moisture to chart; find intersection of the two values, read down to find Gals./1000 CFM.

(2) Plate Water Requirements (at free flow) is found by applying inlet dust load to average consumption curve; at intersection, read down to find Gals./1000 CFM.

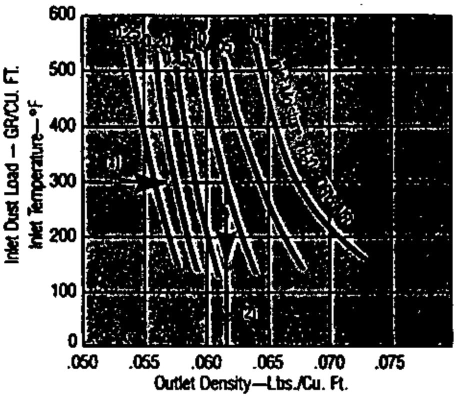
Example: Given an inlet temperature of 300°F., inlet moisture content of 0.10 #H_2O/#Dry Air, 7 Grains/Cu. Ft. inlet dust load and inlet volume of 6000 CFM.:

Spray Water Requirements (1) = 1.20 Gals/1000 CFM x 6000 = 7.20 GPM @ 20 psig

Plate Water Requirements (2) = 1.70 Gals./1000 CFM x 6000 = 10.20 GPM @ Free Flow

Total Water Requirements = 17.40 GPM

Density Correction



Outlet density is required in order to size exhaust equipment—ductwork and fans. At the intersection of inlet temperature and inlet moisture lines on chart, read down to find outlet density.

Example: Given (1) an inlet temperature of 300°F. and (2) inlet moisture content of 0.10 #H_2O/#, the chart reflects an outlet density of .0615 #/Cu. Ft.

Pressure Drop @ 70°F.

NUMBER OF STAGES	NORMAL CAP'Y (INCHES, W.G.)	MAX. CAP'Y (INCHES, W.G.)
ONE STAGE	3.0	4.25
TWO STAGE	4.5	6.4
THREE STAGE	6.0	8.5

Pressure drop is an important consideration in evaluating the efficiency expected of a scrubber in a given application and in fan, drive and motor.

When high efficiency is required, the use of additional stages provides a corresponding increase in pressure drop.

The above chart shows standard pressure drop in inches, w.g., across scrubber for 1 stage, 2 stages and 3 stages.

To correct pressure drop to operating conditions, multiply standard pressure drop by the ratio of outlet density to standard density.

Example: Using .0615 #/Cu. Ft. Dry Air from Density Correction example and the 1 stage average capacity pressure drop of 3" at 70°F. (density .075) the operating pressure drop is: 3" H_2O x .0615/.075 = 2.46 inches, w.g.

TWO STAGE DIMENSIONS

Impinjet Number	Straight Side A	Over-All Height B	Spray Water Inlet C	Plate Water Inlet D	Inlet Flange Dia. E	Outlet Flange Dia. F
215	7'4"	8' 4"	1' 3"	5' 3"	6"	7"
220	7'6"	8' 9"	1' 5"	5' 5"	8"	8"
225	7'9"	9' 2"	1' 7"	5' 7"	10"	11"
230	8'0"	9' 8"	1' 9"	5' 9"	1' 0"	1' 1"
235	8'3"	10' 2"	1'11"	5'11"	1' 2"	1' 3"
240	8'6"	10' 7"	2' 1"	6' 1"	1' 4"	1' 5"
245	8'9"	11' 1"	2' 3"	6' 3"	1' 6"	1' 7"
250	9'3"	11'10"	2' 3"	6' 3"	1' 7"	1' 9"
255	9'6"	12' 3"	2' 5"	6' 5"	1' 9"	1'11"
260	9'9"	12' 9"	2' 8"	6' 8"	2' 0"	2' 2"
265	10'0"	13' 3"	2'10"	6'10"	2' 2"	2' 4"
270	10'3"	13'10"	3' 1"	7' 1"	2' 4"	2' 6"
275	10'6"	14' 3"	3' 3"	7' 3"	2' 6"	2' 8"
280	11'3"	15' 3"	3' 6"	7' 6"	2' 8"	2'10"
285	11'9"	15'11"	4' 0"	8' 0"	2'10"	3' 0"
290	12'0"	16' 5"	4' 3"	8' 3"	3' 0"	3' 2"
295	12'6"	17' 2"	4' 8"	8' 8"	3' 2"	3' 4"
2100	12'9"	17' 8"	4'11"	8'11"	3'0"x3' 2"	3' 7"
2105	13'0"	18' 1"	5' 2"	9' 2"	3'0"x3' 6"	3' 9"
2110	13'6"	18'10"	5' 6"	9' 6"	3'0"x3'10"	3'11"
2115	15'0"	20' 7"	6' 0"	10' 0"	3'0"x4' 2"	4' 1"
2120	15'3"	21' 1"	6' 3"	10' 3"	3'0"x4' 6"	4' 4"
2125	15'6"	21' 7"	6' 6"	10' 6"	3'0"x5' 0"	4' 6"
2130	15'9"	22' 1"	6' 9"	10' 9"	3'0"x5' 4"	4' 8"
2135	16'0"	22' 6"	7' 0"	11' 0"	3'0"x5'10"	4'10"
2140	16'3"	23' 0"	7' 3"	11' 3"	3'0"x6' 4"	5' 0"

THREE STAGE DIMENSIONS

Impinjet Number	Straight Side A	Over-All Height B	Spray Water Inlet C	Plate Water Inlet D	Inlet Flange Dia. E	Outlet Flange Dia. F
315	9'4"	10' 4"	1' 3"	7' 3"	6"	7"
320	9'6"	10' 9"	1' 5"	7' 5"	8"	8"
325	9'9"	11' 2"	1' 7"	7' 7"	10"	11"
330	10'0"	11' 8"	1' 9"	7' 9"	1' 0"	1' 1"
335	10'3"	12' 2"	1'11"	7'11"	1' 2"	1' 3"
340	10'6"	12' 7"	2' 1"	8' 1"	1' 4"	1' 5"
345	10'9"	13' 1"	2' 3"	8' 3"	1' 6"	1' 7"
350	11'3"	13'10"	2' 3"	8' 3"	1' 7"	1' 9"
355	11'6"	14' 3"	2' 5"	8' 5"	1' 9"	1'11"
360	11'9"	14' 9"	2' 8"	8' 8"	2' 0"	2' 2"
365	12'0"	15' 3"	2'10"	8'10"	2' 2"	2' 4"
370	12'3"	15'10"	3' 1"	9' 1"	2' 4"	2' 6"
375	12'6"	16' 3"	3' 3"	9' 3"	2' 6"	2' 8"
380	13'3"	17' 3"	3' 6"	9' 6"	2' 8"	2'10"
385	13'9"	17'11"	4' 0"	10' 0"	2'10"	3' 0"
390	14'0"	18' 5"	4' 3"	10' 3"	3' 0"	3' 2"
395	14'6"	19' 2"	4' 8"	10' 8"	3' 2"	3' 4"
3100	14'9"	19' 8"	4'11"	10'11"	3'0"x3' 2"	3' 7"
3105	15'0"	20' 1"	5' 2"	11' 2"	3'0"x3' 6"	3' 9"
3110	15'6"	20'10"	5' 6"	11' 6"	3'0"x3'10"	3'11"
3115	17'0"	22' 7"	6' 0"	12' 0"	3'0"x4' 2"	4' 1"
3120	17'3"	23' 1"	6' 3"	12' 3"	3'0"x4' 6"	4' 4"
3125	17'6"	23' 7"	6' 6"	12' 6"	3'0"x5' 0"	4' 6"
3130	17'9"	24' 1"	6' 9"	12' 9"	3'0"x5' 4"	4' 8"
3135	18'0"	24' 6"	7' 0"	13' 0"	3'0"x5'10"	4'10"
3140	18'3"	25' 0"	7' 3"	13' 3"	3'0"x6' 4"	5' 0"

The Impinjet® Is Available Three Ways to Fit Your Dust or Fume Problems

Sly makes the Impinjet Scrubber in different configurations to meet different installation space problems. Each shape, however, contains the same high quality internal parts. Each type of scrubber employs the key to thorough, high efficiency cleaning— our singular impingement plate and baffle grid design.

These made-to-order shapes are:

Cylindrical-Round - capacities to 70,000 CFM. Shipped assembled—reduces installation time.

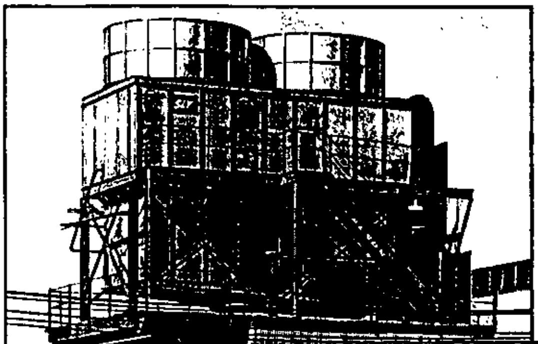
Square-Rectangular - 40,000 to over 1,000,000 CFM capacities. Shipped assembled to minimize field erection costs or shipped knocked down as required.

Impinjet Internals - components for use in silos, stacks or other receptacles are custom engineered to the container for the application. Field welding or cutting may not be required.

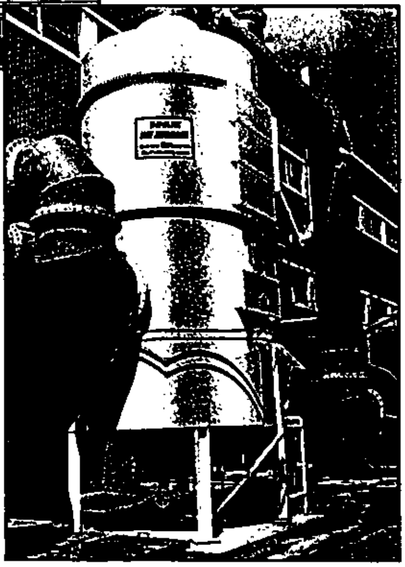
Three unique shapes accommodate unusual space limitations. This is only one of the reasons why Round and Square-rectangular Impinjet scrubbers and Impinjet Internals are progressive answers to many dust and fume control problems.

More important, each scrubber is engineered to economically meet capacity, temperature and liquid requirements for specific dust and fume applications.

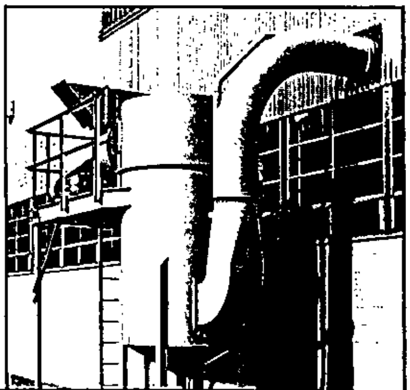
Depth of know-how and quality construction assure highest cleaning efficiencies, from the smallest 200 CFM capacity units to the large 1,000,000 CFM capacity models.



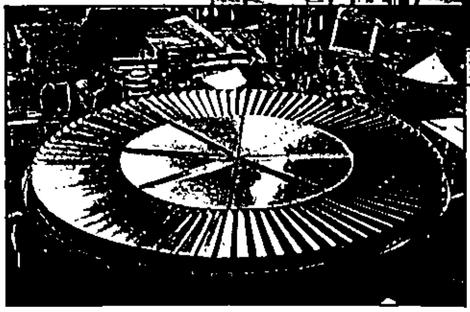
Rectangular Scrubber -Republic Steel Corp. Unit is used in processing coal. Operating to 146,000 CFM at 200°F, the scrubber collects coal dust and fly ash from a fluid bed coal dryer exhaust.



Round Scrubber - Sylvania Electric Products, Inc. This three stage Impinjet is used for dust control and fume absorption. The unit is designed to handle 30,000 CFM at 180°F. Polyvinyl dichloride (PVDC) impingement baffle plates and butyl lined shell are employed to resist corrosion. Caustic solutions are recirculated via an integral reservoir in this Scrubber's base.



Round Scrubber - Sealed Power Corp. Vents spin molding machines. Build to operate at 5,000 CFM, 120°F, the scrubber has provisions for increasing capacity to 6,000 CFM. Note that this unit has top horizontal discharge instead of vertical discharge as well as a fan and motor platform.



Impinjet Mist Eliminator - 20 feet in diameter in final stage of fabrication. Installation in customer's concrete stave silo.

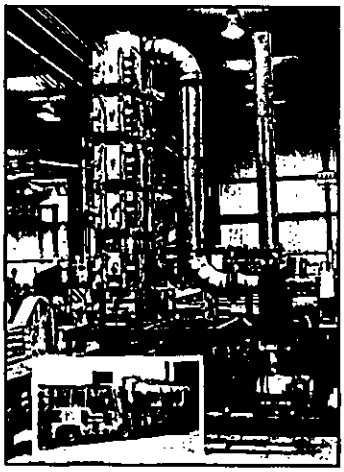
How To Select Your Venturi or Impinjet® Scrubber's Materials of Construction

MAX. USE TEMP-GAS STREAM °F MAX. USE TEMP-SOLUTION °F		400 140	— 200	— 200	— 200	170 140	400 220
Material Collected (5% by Weight)	**Mild Steel**	**Mild Steel Coated**	**304 S/S**	**316 S/S**	**316-L S/S**	**PVC**	**FRP**
Acetic Acid	N	G	E	E	E	E	E
Alum	N	G	E	E	E	E	E
Aluminum Chloride	N	E	N	N	N	E	E
Aluminum Sulfate	N	E	E	E	E	E	E
Ammonia (Wet)	N	G	E	E	E	N	E
Ammonium Chloride	N	E	G	G	G	E	E
Ammonium Hydroxide	N	N	E	E	E	E	E
Ammonium Nitrate	N	E	E	E	E	E	E
Ammonium Phosphate	N	G	G	G	G	E1	E
Ammonium Sulfate	N	G	G1	E	E	E	E
Black Liquor (NaOH, Na_2S, Na_2CO_3)	N	N	N	N	G	E	E
Borax	N	G	E	E	E	E	E
Boric Acid	N	G	E	E	E	E	E
Calcium Chloride	N	G	G	E	E	E	E
Calcium Hypochlorite	N	N	N	N	N	E	E
Carbonic Acid	N	G	E	E	E	E	E
Chlorine	N	N	N	N	N	E	E
Chlorine Dioxide	N	N	N	N	N	E2	E
Chromic Acid	N	N	G	G	G	E3	E
Citric Acid	N	G	E	E	E	E	E
Copper Chloride	N	N	N	N	N	E	E
Copper Sulfate	N	N	E	E	E	E	E
Coal Dust	E	E	E	E	E	E	E
Coal Dust (Dryers—SO_2)	N	G	E	E	E	N	N
Ferric Chloride	N	N	N	N	N	E	E
Ferric Sulfate	N	N	E	E	E	E	E
Ferrous Sulfate	N	N	E	E	E	E	E
Hydrochloric Acid	N	G	N	N	N	E	E
Hydrofluoric Acid	N	N	N	N	N	G	E8
Hydrogen Sulfide	N	N	N	G	G	E	E
Hydrogen Peroxide	N	N	G	G	G	E	E
Magnesium Chloride	N	N	G	G	G	E	E
Magnesium Hydroxide	N	N	G	G	G	E	E
Magnesium Sulfate	N	N	G	G	G	E	E
Mixed Acid (15% Nitric & 4% HF)	N	N	N	N	N	G4	E7
Nitric Acid	N	N	E	E	E	E	E8
Oleic Acid	N	N	G4	G4	G4	N	E
Phosphoric Acid	N	N	G5	G5	G5	E	E
Sodium Carbonate	N	N	E	E	E	E	E7
Sodium Chloride	N	E	G5	E5	E5	E	E
Sodium Hydroxide	E6	E6	E	E	E	E	E
Sodium Hypochlorite	N	N	G4	G4	G4	E	E6
Sodium Nitrate	G	G	E	E	E	E	E
Sodium Sulfate	G	G	E	E	E	E	E
Sodium Sulfite	G	G	E5	E5	E5	E	E
Sulfur Dioxide	N	N	G	E	E	E	E
Sulfuric Acid	N	G	E	E	E	E	E
Sulfurous Acid	N	G	G5	G5	G5	E	E
Zinc Chloride	N	N	N	G	G	E	E
Zinc Sulfate	N	N	N	G	G	E	E

E = Excellent
G = Good
N = Not Suitable for Use

1 Under basic or neutral conditions only
2 At ambient temperature
3 Aqueous solution only

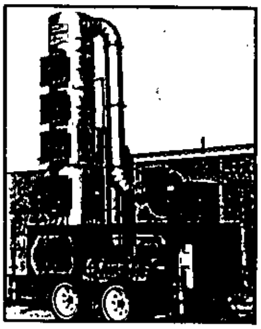
4 to 100°F
5 to 120°F
6 to 135°F
7 to 140°F
8 to 180°F



Field Testing Units & Packaged Systems

As an optional service, we can provide "Package Systems" to include such auxiliaries as fans, pumps, strainers, recirculation tanks, pH controls, flow control and measurement, and interconnecting piping and fittings. A typical such package is the Impinjet test unit shown in photo.

For a quotation on packaged auxiliaries, please furnish a list of items to be included and as much detail on specifications as possible. Quotations on packaged auxiliaries, being custom engineered, will require more lead time in preparation than our standard product line.



For actual field testing at your plant, we can send a portable Impinjet scrubber. The rental cost is nominal.

APPENDIX C

SCREENING THRESHOLD TECHNIQUE

STATE OF FLORIDA

DEPARTMENT OF ENVIRONMENTAL REGULATION

TWIN TOWERS OFFICE BUILDING
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32301-8241

BOB GRAHAM
GOVERNOR

VICTORIA J. TSCHINKEL
SECRETARY

October 28, 1986

Mr. David Buff
KBN Engineering and Applied
Sciences, Inc.
P. O. Box 14288
Gainesville, Florida 32604

Re: Jefferson Smurfit PSD Permit Application

Dear Dave:

In order to reduce the number of possible disputes with EPA with regard to which sources need to be included in a PSD permit modeling exercise, the department is recommending that you use the EPA-approved North Carolina "Screening Threshold" method. I have included a copy of the paper describing the technique, as well as correspondence between the State of North Carolina and the EPA regarding this method. We further recommend that the screening area boundary be 50 km.

Should you wish to modify this technique or present one of your own, the department will review your proposal and submit it to the EPA for approval.

With regard to your emission inventory, we have included a list of stack parameters for the Container Corporation of America facility (Table 1) as presented to the department by the company on their Annual Operating Report for 1985. Furthermore, we request that you contact the Jacksonville local program in order to verify the SO_2 emissions for the two bark-fired boilers at the Jacksonville Kraft facility. Our records are unclear with regard to these sources.

If you have any questions regarding the proposed screening technique or on the stack parameter data please call me at (904) 488-1344.

Sincerely,

Max A. Linn
Meteorologist
Bureau of Air Quality
Management

ML/ps

Protecting Florida and Your Quality of Life

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

RECEIVED
SEP 12 1985
AIR QUALITY

SEP 5 1985

REF: APT-AP

Eldewins Haynes
Air Permit Unit
State of North Carolina Department of
Natural Resources & Community Development
512 North Salisbury Street
Raleigh, North Carolina 27611

Subject: A Screening Method for PSD

Dear Mr. Haynes:

This is to acknowledge receipt of your July 22, 1985, letter containing a screening procedure for eliminating sources from the emission inventory for modeling purposes. EPA has reviewed your submittal and has determined that your screening procedure is consistent with the PSD Workshop Manual. Therefore, approval is hereby given to use the screening procedure.

Sincerely yours,

Bruce P. Miller

Bruce P. Miller, Acting Chief
Air Programs Branch

DER
APR 14 1986
BAQM

State of North Carolina
Department of Natural Resources and Community Development
Division of Environmental Management
512 North Salisbury Street • Raleigh, North Carolina 27611

James G. Martin, Governor
S. Thomas Rhodes, Secretary

R. Paul Wilms
Director

July 22, 1985

Mr. Lewis Nagler
Air Management Branch
EPA Region IV
345 Courtland Street
Atlanta, Georgia 30365

Dear Mr. Nagler:

Subject: A Screening Method for PSD

A simple screening procedure which is applicable to PSD has been developed by the North Carolina Air Quality Section. The "Screening Threshold" method is designed to rapidly and objectively eliminate from the emissions inventory those sources which are beyond the PSD impact area yet within the screening area, but are not likely to have significant interaction with the PSD source. Sources which are flagged by this procedure may then be evaluated with conventional screening techniques, or else be included in refined modeling.

Page I-C-18 of the PSD Workshop Manual does state "A simple screening model technique can be used to justify the exclusion of certain emissions...Such exclusions should be justified and documented." The "Screening Threshold" method is documented in the attachment.

We would very much appreciate your comments and ultimate approval. Please feel free to direct any questions or comments to me in writing or by phone at (919) 733-7015.

Sincerely,

Eldewins Haynes

Eldewins Haynes, Meteorologist
Air Permit Unit

Attachment

cc: Mr. Ogden Gerald
Mr. Mike Sewell
Mr. Sammy Amerson
Mr. Jerry Clayton
Mr. Richard Laster
Regional Air Engineers

Pollution Prevention Pays

P.O. Box 27687, Raleigh, North Carolina 27611-7687 Telephone 919-733-7015

"Screening Threshold" Method for PSD Modeling
North Carolina Air Quality Section

This method is best suited for situations where a PSD source has several sources outside its impact area, but within its screening area. The object is to find an effective means to minimize the number of such sources in a model, yet to include all sources which are likely to have a significant impact inside the impact area.

As a first-level screening technique, it is suggested to include those sources within the screening area when

$$Q = 20D$$

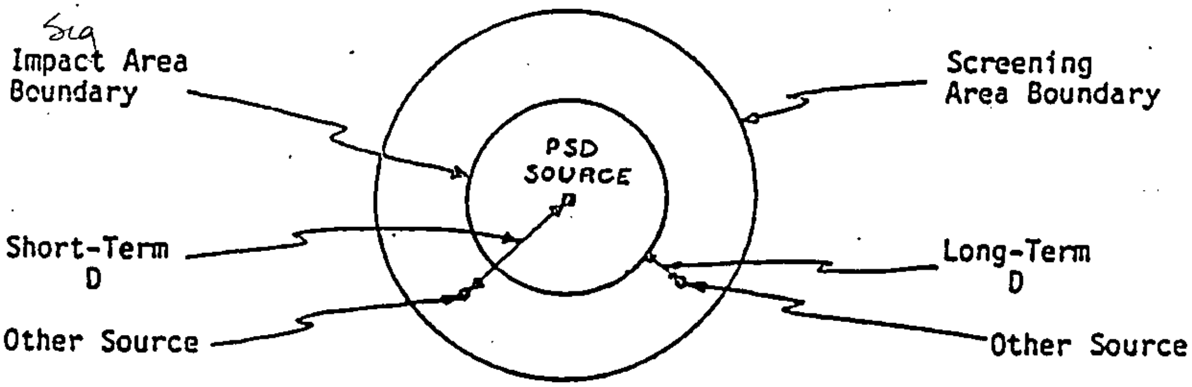
where Q is the maximum emission rate, in tons/year, of the source in the screening area; and D is a distance, in kilometers, from either:

a. the source in the screening area to the nearest edge of the impact area, for long-term analyses

or

b. the source in the screening area to the PSD source defining the impact area, for short-term analyses.

The figure below illustrates the difference between the long-term D and the short-term D.



This method does not preclude the use of alternate screening techniques or of more sophisticated screening techniques given the approval of the review agency. Also, this method does not prevent the review agency from specifying additional sources of interest in the modeling analysis.

The justification for this "Screening Threshold Method" rests upon the following assumptions:

a. effective stack height = 10 meters
b. stability class D (neutral)
c. 2.5 meter/second wind speed
d. mixing height = 300 meters
e. Q = 20D = critical emission rate for a given pollutant
f. one-hour concentrations derived from figure 3-5D in Turner's WADE or from PTDIS.
g. 3-hour and 24-hour concentrations estimated using "Vol. 10R". Annual impacts are 1/7 of 24 hour impacts.

The results, for various distances, are shown in the table below:

D (km)	Q (T/yr)	1-hr Conc. (ug/m^3)	3-hr Conc. (ug/m^3)	24-hr Conc. (ug/m^3)	Annual Conc. (ug/m^3)
0.5	10	47	42	19	2.7
1.0	20	32	29	13	1.9
1.5	30	27	24	10	1.4
2.0	40	23	21	9	1.3
3	60	18	16	7	1.0
4	80	17	15	7	1.0
5	100	14	13	6	1
6	120	13	12	5	1
10	200	10	9	4	1
20	400	7	6	3	1
30	600	6	6	3	1
40	800	6	6	3	1
50	1000	7	6	3	1

The "Screening Threshold" method is conservative. Most sources either have effective stack heights greater than 10 meters, or they have several short stacks spread out over an industrial complex. Thus, actual modeled concentrations will most likely be lower than the "Screening Threshold" would indicate in the table above. One implication of the table is that all major sources within 5 km of the subject PSD source or within 5 km of the PSD source's impact area should be scrutinized before being exempted from the final emissions inventory.

The "Screening Threshold" method is in qualitative agreement with the suggestions on page I-C-18 of the Prevention of Significant Deterioration Workshop Manual (1980). On that page, it is suggested that a 100 T/Y source 10 km outisde the impact area may be excluded from the analysis. The above table would exclude a 100 T/Y source more than 5 km beyond the impact area for long-term analyses or more than 5 km away from the PSD source for short-term analyses; if the source is inside the impact area, it must be included regardless of the "Screening

Threshold". The PSD Workshop Manual also states on page I-C-18 that a 10,000 T/Y source 40 km outside the impact area would probably have to be included in the increment analysis. By the "Screening Threshold" method, the critical distance D = Q/20 = 10,000/20 = 500 km. Thus a 10,000 T/Y source within 500 km would always be included for short-term and long-term analyses if within the screening area.

This "Screening Threshold" method is quick, inexpensive to execute, conservative, and consistent with the intent of the PSD Workshop Manual.

APPENDIX D

SO_2 EMISSION INVENTORY

Table D-1. Summary of SO2 Stack and Operating Parameters for Individual Sources Considered in the AAQS Modeling Analysis (Page 2 of 4)

APIS Number	Facility	APIS Source Number	Source Description	Maximum SO2 Emissions (g/sec)	Location Relative To Proposed*		Stack Data		Operating Data		Included in the Modeling Analysis?
					X (m)	Y (m)	Height (m)	Diameter (m)	Temperature (K)	Velocity (m/sec)	
40TPA530056	IMC-Prairie	01	Lime Bucket Elev	3.1	-10700	6400	27.43	0.30	311	12.80	No
40TPA530080	Imperial Phosphate	01	GNSP Dryer	6.9	-8800	-11100	27.43	1.52	333	20.42	Yes
		02	Boiler	1.0	-8800	-11100	27.43	0.61	494	7.01	
40TPA530167	Laidlaw Environ. Serv.	02	Boiler	6.9	10400	11300	6.10	0.67	489	5.79	No
40TPA530057	Conserv. Chemicals	02	DAP Cooler	0.3	-14900	3600	15.85	0.76	322	20.12	Yes
		05	DAP #1	42.0	-14900	3600	45.72	2.29	352	10.30	
		12	Phos Rock Dryer	3.3	-14900	3600	24.69	2.29	328	3.66	
		15	Standby Boiler	0.1	-14900	3600	8.23	0.61	533	13.72	
		16	Boiler	0.2	-14900	3600	11.89	0.98	533	8.84	
40TPA530047	Mobil Chem Co. Nichols	01	Rotary Rk Dryer #1	19.7	-15200	4700	24.38	2.29	344	12.50	Yes
		02	Rotary Rk Dryer #2	19.7	-15200	4700	24.38	2.29	344	12.50	
		03	Rotary Kiln	0.05	-15200	4700	30.48	1.10	339	18.90	
		04	Dryer #4	2.4	-15200	4700	25.91	2.29	339	15.21	
		08	Boiler	1.8	-15200	4700	3.96	0.76	522	1.83	
40TPA530059	IMC - New Wales	02	Sulf Acid Plt #1	61.0	-16900	-1200	60.96	2.59	350	15.30	Yes
		03	Sulf Acid Plt #2	61.0	-16900	-1200	60.96	2.59	350	15.30	
		04	Sulf Acid Plt #3	61.0	-16900	-1200	60.96	2.59	350	15.30	
		09	DAP Plant #1	9.4	-16900	-1200	40.54	2.13	314	14.94	
		10	GTSP	5.6	-16900	-1200	40.54	1.83	316	20.42	
		13	Standby Boiler	71.7	-16900	-1200	28.96	1.71	564	17.07	
		27	Granulation Plant	2.3	-16900	-1200	52.43	2.44	322	13.11	
		42	Sulf Acid Plt #4	61.0	-16900	-1200	60.66	2.59	350	15.30	
		44	Sulf Acid Plt #5	61.0	-16900	-1200	60.66	2.59	350	15.30	
		46	DAP Plant #2	5.6	-16900	-1200	36.58	1.83	319	20.15	
40TPA530044	Gardinier	01	Phos Rock Dryer	33.8	1700	-17300	19.20	2.90	290	7.01	Yes
40HIL290102	Mobil Big Four Mine	01	Phos Rock Dryer	16.4	-18900	-11000	30.48	1.83	333	12.50	Yes
NA	AMAX	NA	NA	0.6	-18800	-12900	8.20	0.41	505	7.57	Yes
		NA	NA	16.4	-18800	-12900	30.48	1.83	334	7.26	
NA	Hardee Power Station	NA	5 CT Units	277.6	-8800	-23200	22.86	4.88	389	23.90	Yes

Table D-1. Summary of SO2 Stack and Operating Parameters for Individual Sources Considered in the AAQS Modeling Analysis (Page 3 of 4)

APIS Number	Facility	APIS Source Number	Source Description	Maximum SO2 Emissions (g/sec)	Location Relative To Proposed*		Stack Data		Operating Data		Included in the Modeling Analysis?
					X (m)	Y (m)	Height (m)	Diameter (m)	Temperature (K)	Velocity (m/sec)	
40HIL290075	Consolidated Minerals	03	Kiln #2	0.003	-19800	15700	46.33	1.77	300	9.45	Yes
		20	Kewanee Boiler	0.1	-19800	15700	6.10	0.37	605	20.12	
		22	Fluid Bed Reac #1	11.6	-19800	15700	46.33	1.77	300	11.89	
		24	Fluid Bed Reac #2	11.6	-19800	15700	46.33	1.77	295	10.97	
		26	Kilns 3,4,5	15.4	-19800	15700	46.33	1.77	298	13.11	
40TPA530004	Lakeland Power/McIntosh	01	Boiler #1	341.3	-4400	25600	45.72	2.74	419	23.77	Yes
		02	Peaking Unit #2	1.5	-4400	25600	6.10	0.79	653	23.47	
		03	Peaking Unit #3	1.5	-4400	25600	6.10	0.79	653	23.47	
		04	Peaking Unit #1	8.3	-4400	25600	10.97	2.80	791	0.30	
		05	Unit #2 Generator	25.7	-4400	25600	47.55	3.17	403	21.03	
		06	Unit #3-Coal	500.1	-4400	25600	76.20	4.88	350	19.69	
40TPA530003	Lakeland Power/Larsen	01	Unit #4	93.3	-4600	25600	50.29	3.05	433	5.49	Yes
		02	Steam Gen #5	0.4	-4600	25600	50.29	3.05	444	6.40	
		03	Steam Gen #6	2.8	-4600	25600	50.29	3.05	444	6.40	
		04	Steam Gen #7	18.7	-4600	25600	50.29	3.05	444	6.71	
		06	Turbine #3	0.2	-4600	25600	9.75	1.52	700	171.30	
		07	Turbine #2	0.01	-4600	25600	9.75	1.52	700	171.30	
		NA	CT	29.1	-4600	25600	30.48	5.79	783	28.22	
40HIL290101	IMC - Fort Lonesome	01	Phos Rk Dryer #1	18.4	-24100	-12700	38.10	2.90	339	10.12	Yes
		02	Phos Rk Dryer #2	21.2	-24100	-12700	38.10	2.44	346	18.41	
		05	Fuel Preheater	0.3	-24100	-12700	6.10	0.30	616	8.23	
40TPA530002	Citrus World	01	Peel Dryer	8.1	27400	6700	22.86	0.98	323	10.67	Yes
		02	Boiler #4	0.003	27400	6700	12.19	1.71	355	8.23	
		03	Boiler #5	0.001	27400	6700	12.19	1.10	505	1.22	
		04	Boiler #3	0.004	27400	6700	12.19	1.10	505	1.22	
		05	Boiler #2	0.004	27400	6700	12.19	0.85	505	2.44	
		07	Peel Dryer	9.1	27400	6700	22.86	0.76	325	12.19	
		13	Peel Dryer	8.1	27400	6700	24.38	0.76	313	21.95	
		17	Boiler #1	0.001	27400	6700	12.19	1.10	505	1.22	
		20	Gas Turbine	0.003	27400	6700	9.14	0.91	558	32.92	
40TPA250009	Wachula City Power	01	Peeking Unit #1	1.0	4800	-33600	10.67	0.55	505	21.95	No
		02	Peeking Unit #2	1.0	4800	-33600	10.67	0.30	589	57.91	
		03	Peeking Unit #3	1.0	4800	-33600	10.67	0.55	505	32.00	
		04	Peeking Unit #4	1.0	4800	-33600	10.67	0.55	505	32.00	
		05	Peeking Unit #5	1.0	4800	-33600	10.67	0.55	505	32.00	

Table D-1. Summary of SO2 Stack and Operating Parameters for Individual Sources Considered in the AAQS Modeling Analysis (Page 4 of 4)

					Location Relative To Proposed*		Stack Data		Operating Data		
APIS Number	Facility	APIS Source Number	Source Description	Maximum SO2 Emissions (g/sec)	X (m)	Y (m)	Height (m)	Diameter (m)	Temperature (K)	Velocity (m/sec)	Included in the Modeling Analysis?
40TPA530019	Citrus Hill Manufacturing	01	Citrus Peel Dryer	11.5	34300	-12300	23.16	0.98	350	20.12	No
		04	Steam Boiler #1	8.3	34300	-12300	20.73	0.98	458	11.28	
		05	Steam Boiler #2	8.0	34300	-12300	18.90	1.07	458	9.45	
		07	Boiler #3	0.003	34300	-12300	21.95	0.91	550	9.14	
40TPA250011	American Orange Corp.	01	Heat Evaporator	6.2	16200	-33300	19.51	0.85	333	10.67	No
		02	Citrus Peel Dryer	6.2	16200	-33300	10.67	3.96	358	1.52	
40TPA530001	Alcoma Packing	01	Oil Fired Boiler	5.8	38000	4900	21.34	0.61	480	21.95	No
		04	Cleaver Boiler	5.3	38000	4900	21.34	0.70	480	15.85	
		05	Citrus Peel Dryer	16.4	38000	4900	27.13	0.98	333	10.06	
NA	C F Industries	NA	Unit C	54.6	-25600	35400	60.35	2.44	353	17.77	Yes
		NA	Unit D	54.6	-25600	35400	60.35	2.44	353	17.77	
40HIL290261	Hillsborough County RRF	01	Unit #1	7.1	-45400	12100	50.00	1.80	491	18.29	No
		02	Unit #2	7.1	-45400	12100	50.00	1.80	491	18.29	
		03	Unit #3	7.1	-45400	12100	50.00	1.80	491	18.29	
52FTM280003	FPL-Avon Park	02	Unit #2	1.7	37800	-30100	59.74	1.46	433	57.00	No
		03	Peaking Unit #1	0.1	37800	-30100	16.76	3.05	728	129.24	
		04	Peaking Unit #2	0.1	37800	-30100	45.42	3.35	728	106.68	
40HIL290076	Delta Asphalt	01	Asphalt Batch	3.8	-41500	24800	8.53	1.16	422	24.38	No

Note: NA = data not available.

* Proposed facility located at 413.6 km east and 3080.6 km north.

Table D-2. Summary of Stack and Operating Parameters for Combined Sources Considered in the AAQS Modeling Analysis (Page 1 of 2)

ARAPDXD2
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				Location Relative To Proposed*		Stack Data		Operating Data		
APIS Number	Facility	APIS Source Numbers	Maximum SO2 Emissions (g/sec)	X (m)	Y (m)	Height (m)	Diameter (m)	Temperature (K)	Velocity (m/sec)	ISCST Model ID
40TPA530027	IMC Noralyn Mine Road	01	1.2	1100	-300	23.16	1.98	394	17.07	1001
		02	13.3	1100	-300	16.76	2.83	341	8.53	1002
40TPA530053	Farmland Industries	03,04	67.2	-4100	-500	30.48	2.29	355	9.27	118
		05	42.0	-4100	-500	45.72	2.44	355	9.66	119
		28	2.3	-4100	-500	28.96	1.68	605	3.35	1101
40TPA530065	Kaplan Industries	02,03,04	11.4	4700	-1300	4.27	0.40	422	38.16	1201
40TPA530052	C.F. Industries-Bartow	NA	4.3	-5600	1800	9.11	0.70	450	22.49	112
		NA	52.9	-5600	1800	67.06	2.41	351	9.81	113
40TPA530046	W.R. Grace/Sem. Fert.	08,13,14,21,30	62.7	-3800	6100	45.72	2.04	304	9.14	1301
		12,32,33	112.3	-3800	6100	60.96	1.52	341	24.38	1302
		31,39	82.2	-3800	6100	15.24	2.04	333	17.07	1303
40TPA530048	Royster Co.	02,05,09	36.9	-6800	4500	60.96	2.13	360	12.19	1401
40TPA530054	Agrico Chemical-Pierce	01,04	12.0	-9900	-1600	24.38	2.44	321	21.03	1501
40TPA530055	Agrico Chem.-S. Pierce	01,04,05,23,NA	222.1	-6100	-9100	45.72	1.60	350	39.04	1601
40TPA530051	U. S. Agri-Chemicals	06,16,17	132.4	2400	-11600	53.40	2.59	355	15.91	1701
40TPA530080	Imperial Phosphate	01,02	7.9	-8800	-11100	27.43	1.52	333	20.42	1801
40TPA530057	Conserv. Chemicals	02,05,12,15,16	45.9	-14900	3600	45.72	2.29	352	10.30	1901
40TPA530047	Mobil Chem Co. Nichols	01,02,03,04,08	43.7	-15200	4700	24.38	2.29	344	12.50	2001
40TPA530059	IMC - New Wales	02,03,04,42,44	305.0	-16900	-1200	60.96	2.59	350	15.30	2101
		09,10,13,27,46	94.6	-16900	-1200	28.96	1.71	564	17.07	2102
40TPA530044	Gardinier	01	33.8	1700	-17300	19.20	2.90	290	7.01	2201
40HIL290102	Mobil Big Four Mine	01	16.4	-18900	-11000	30.48	1.83	333	12.50	2301
NA	AMAX	NA	0.6	-18800	-12900	8.20	0.41	505	7.57	150
		NA	16.4	-18800	-12900	30.48	1.83	334	7.26	151
NA	Hardee Power Station	NA	277.6	-8800	-23200	22.86	4.88	389	23.90	2401

Table D-2. Summary of Stack and Operating Parameters for Combined Sources Considered in the AAQS Modeling Analysis (Page 2 of 2)

APIS Number	Facility	APIS Source Numbers	Maximum SO2 Emissions (g/sec)	Location Relative To Proposed*		Stack Data		Operating Data		ISCST Model ID
				X (m)	Y (m)	Height (m)	Diameter (m)	Temperature (K)	Velocity (m/sec)	
40HIL290075	Consolidated Minerals	03,20,22,24,26	38.7	-19800	15700	46.33	1.77	298	13.11	2501
40TPA530004	Lakeland Power/McIntosh	01,02,03,04,05	378.3	-4400	25600	45.72	2.74	419	23.77	2601
		06	500.1	-4400	25600	76.20	4.88	350	19.69	55
40TPA530003	Lakeland Power/Larsen	01,02,03,04,05 06,07	115.4	-4600	25600	50.29	3.05	433	5.49	2701
		NA	29.1	-4600	25600	30.48	5.79	783	28.22	2702
40HIL290101	IMC - Fort Lonesome	01,02,05	39.9	-24100	-12700	38.10	2.44	346	18.41	2801
40TPA530002	Citrus World	01,02,03,04,05 07,13,17,20	25.3	27400	6700	22.86	0.76	325	12.19	2901
NA	C. F. Industries	NA	109.2	-25600	35400	60.35	2.44	353	17.77	7

Note: NA = data not available.

* Proposed facility located at 413.6 km east and 3080.6 km north.

Table D-3. Summary of SO2 Stack and Operating Parameters for Sources Considered in the PSD Class II Modeling Analysis

Facility	Maximum SO2 Emissions (g/sec)	Location Relative to Proposed*		Stack Data		Operating Data		ISCST Model ID
		X (m)	Y (m)	Height (m)	Diameter (m)	Temperature (K)	Velocity (m/sec)	
CF Ind. Baseline C,D	-100.8	-25600	35400	60.30	2.44	353	16.40	6
CF Ind. Proposed C,D	109.2	-25600	35400	60.30	2.44	353	17.77	7
Hardee Power Station	277.6	-8800	-23200	22.90	4.88	389	23.90	53
Lakeland McIntosh 3	500.1	-5100	25200	76.20	4.88	350	19.70	55
Hillsborough Cty RRF	21.4	-45400	12100	50.00	1.80	491	18.30	56
Lakeland Util CT	29.11	-4400	22200	30.50	5.79	783	28.22	90
IMC SAP 1,2,3 Baseline	-170.1	-17000	-1700	61.00	2.60	350	14.28	91
IMC SAP 1,2,3 Projected	182.85	-17000	-1700	61.00	2.60	350	15.31	92
IMC SAP 4,5 Projected	121.9	-17000	-1700	60.70	2.60	350	15.31	93
IMC DAP	5.54	-17000	-1700	36.60	1.83	319	20.15	94
CF Bartow Retired H2SO4	-110.6	-5100	2400	30.50	1.68	350	14.60	111
CF Bartow DAP	4.3	-5100	2400	9.10	0.70	450	22.50	112
CF Bartow #7 H2SO4	52.9	-5100	2400	67.10	2.40	351	9.80	113
Conserve	-15.2	-15200	3600	30.50	1.80	308	18.90	115
Conserve #1 H2SO4	42	-15200	3600	45.70	2.30	352	10.30	116
Farmland 1,2 H2SO4	-54.56	-4100	-1100	30.50	1.37	311	20.18	117
Farmland 3,4 H2SO4	67.16	-4100	-1100	30.50	2.29	355	9.27	118
Farmland 5 H2SO4	41.96	-4100	-1100	45.70	2.44	355	9.65	119
IMC Lonesome Mine Dryer 1	18.4	-24000	-12700	38.10	2.90	339	10.13	120
IMC Lonesome Mine Dryer 2	21.17	-24000	-12700	38.10	2.44	346	18.40	121
Royster #1	-257.6	-6900	4600	51.00	2.13	356	9.90	136
Royster #2	35.7	-6900	4600	61.00	2.13	360	12.20	137
USSAC Ft Meade H2SO4 1,2	126	2500	-12000	53.40	2.59	355	15.91	140
USSAC Ft Meade H2SO4 X	-78.8	2600	-11900	29.00	3.02	314	6.77	142
WR Grace Retired H2SO4	-216	-3900	5400	45.70	1.40	352	16.50	143
WR Grace 2 46 16	73.6	-3900	5400	61.00	2.80	346	7.30	144
WR Grace 2 46 17	72	-4100	5900	61.00	1.52	347	28.40	145
AMAX	0.6	-18800	-12900	8.20	0.41	505	7.57	150
AMAX	16.35	-18700	-10800	30.50	1.82	334	7.26	151
Mobil	2.44	-15300	3700	25.90	2.29	339	15.20	154
Agrico Baseline	-75.6	-6100	-9300	45.70	1.60	350	26.40	400
Agrico Proposed	113.5	-6100	-9300	45.70	1.60	350	39.06	410

* Proposed facility located at 413.6 km east to 3080.6 km north.

APPENDIX E

AIR TOXIC MODELING ANALYSIS

Table E-1. Summary of Maximum Pollutant Emission Rates and Concentrations for the Air Toxic Modeling Analysis (Page 1 of 2)

	Emission Rate at 20° Design Temp (lb/hr)		Emission Rate at 100° Design Temp (lb/hr)			Maximum Concentration ($\mu g/m^3$) (20° Design Temperature)			Maximum Concentration ($\mu g/m^3$) (100° Design Temperature)		
Pollutant	CT	CO2	CT	CO2	Averaging Period	CT (A)	CO2 (B)	Total (A+B)	CT (C)	CO2 (D)	Total (C+D)
Antimony	0.0215	0.0010	0.0167	0.0010	8-hour	0.0058	0.0000	0.0058	0.0063	0.0000	0.0063
					24-hour	0.0029	0.0000	0.0029	0.0033	0.0000	0.0033
					Annual	0.000043	0.000016	0.000059	0.000042	0.000015	0.000057
Arsenic	0.0041	0.0002	0.0032	0.0002	8-hour	0.0011	0.0000	0.0011	0.0012	0.0000	0.0012
					24-hour	0.00056	0.0000	0.00056	0.00063	0.0000	0.00063
					Annual	0.000008	0.000003	0.000011	0.000008	0.000003	0.000011
Barium	0.0192	0.0009	0.0149	0.0009	8-hour	0.0052	0.0000	0.0052	0.0056	0.0000	0.0056
					24-hour	0.0026	0.0000	0.0026	0.0030	0.0000	0.0030
					Annual	0.000038	0.000014	0.000052	0.000037	0.000013	0.000051
Beryllium	0.0025	0.0001	0.0019	0.0001	8-hour	0.00066	0.00000	0.00066	0.00072	0.00000	0.00072
					24-hour	0.00033	0.00000	0.00033	0.00038	0.00000	0.00038
					Annual	0.000005	0.000002	0.000007	0.000005	0.000002	0.000007
Cadmium	0.0103	0.0005	0.0080	0.0005	8-hour	0.0028	0.0000	0.0028	0.0030	0.0000	0.0030
					24-hour	0.0014	0.0000	0.0014	0.0016	0.0000	0.0016
					Annual	0.000021	0.000008	0.000028	0.000020	0.000007	0.000027
Chlorine	0.0265	0.0013	0.0206	0.0012	8-hour	0.0071	0.0000	0.0071	0.0078	0.0000	0.0078
					24-hour	0.0036	0.0000	0.0036	0.0041	0.0000	0.0041
					Annual	0.000053	0.000019	0.000072	0.000052	0.000018	0.000070
Chromium	0.0467	0.0023	0.0363	0.0022	8-hour	0.013	0.000	0.013	0.014	0.000	0.014
					24-hour	0.0063	0.0000	0.0063	0.0072	0.0000	0.0072
					Annual	0.000093	0.000034	0.00013	0.000091	0.000032	0.00012
Cobalt	0.0089	0.0004	0.0069	0.0004	8-hour	0.0024	0.0000	0.0024	0.0026	0.0000	0.0026
					24-hour	0.0012	0.0000	0.0012	0.0014	0.0000	0.0014
					Annual	0.000018	0.000007	0.000024	0.000017	0.000006	0.000024
Copper	0.2755	0.0133	0.2137	0.0127	8-hour	0.074	0.000	0.074	0.081	0.000	0.081
					24-hour	0.037	0.000	0.037	0.043	0.000	0.043
					Annual	0.00055	0.00020	0.00075	0.00054	0.00019	0.00073
Ethanolamine	0.0	37.5	0.0	37.5	8-hour	0.0	31.2	31.2	0.0	31.2	31.2
					24-hour	0.0	12.4	12.4	0.0	12.4	12.4
					Annual	0.00	1.19	1.19	0.00	1.19	1.19
Fluoride	0.0320	0.0015	0.0248	0.0015	8-hour	0.0086	0.0000	0.0086	0.0094	0.0000	0.0094
					24-hour	0.0043	0.0000	0.0043	0.0049	0.0000	0.0049
					Annual	0.000064	0.000023	0.000087	0.000062	0.000022	0.000085

Table E-1. Summary of Maximum Pollutant Emission Rates and Concentrations for the Air Toxic Modeling Analysis (Page 2 of 2)

Pollutant	Emission Rate at 20° Design Temp (lb/hr)		Emission Rate at 100° Design Temp (lb/hr)		Averaging Period	Maximum Concentration ($\mu g/m^3$) (20° Design Temperature)			Maximum Concentration ($\mu g/m^3$) (100° Design Temperature)		
	CT	CO2	CT	CO2		CT (A)	CO2 (B)	Total (A+B)	CT (C)	CO2 (D)	Total (C+D)
Formaldehyde	0.3985	0.0230	0.3091	0.0222	8-hour	0.11	0.00	0.11	0.12	0.00	0.12
					24-hour	0.053	0.000	0.053	0.062	0.000	0.062
					Annual	0.00079	0.00035	0.00114	0.00078	0.00033	0.00111
Lead	0.0088	0.0004	0.0068	0.0004	8-hour	0.0023	0.0000	0.0023	0.0026	0.0000	0.0026
					24-hour	0.0012	0.0000	0.0012	0.0014	0.0000	0.0014
					Annual	0.000017	0.000006	0.000024	0.000017	0.000006	0.000023
Manganese	0.0063	0.0003	0.0049	0.0003	8-hour	0.0017	0.0000	0.0017	0.0019	0.0000	0.0019
					24-hour	0.0009	0.0000	0.0009	0.0010	0.0000	0.0010
					Annual	0.000013	0.000005	0.000017	0.000012	0.000004	0.000017
Mercury	0.0030	0.0001	0.0023	0.0001	8-hour	0.0008	0.0000	0.0008	0.0009	0.0000	0.0009
					24-hour	0.0004	0.0000	0.0004	0.0005	0.0000	0.0005
					Annual	0.000006	0.000002	0.000008	0.000006	0.000002	0.000008
Nickel	0.1673	0.0081	0.1297	0.0077	8-hour	0.045	0.000	0.045	0.049	0.000	0.049
					24-hour	0.022	0.000	0.022	0.026	0.000	0.026
					Annual	0.00033	0.00012	0.00046	0.00033	0.00012	0.00044
Polyorganic Matter	0.0003	0.0001	0.0002	0.0001	8-hour	0.000074	0.000000	0.000074	0.000080	0.000000	0.000080
					24-hour	0.000037	0.000000	0.000037	0.000042	0.000000	0.000042
					Annual	0.000001	0.000002	0.000002	0.000001	0.000002	0.000002
Selenium	0.0231	0.0011	0.0179	0.0011	8-hour	0.0062	0.0000	0.0062	0.0068	0.0000	0.0068
					24-hour	0.0031	0.0000	0.0031	0.0036	0.0000	0.0036
					Annual	0.000046	0.000017	0.000063	0.000045	0.000016	0.000061
Sulfuric Acid Mist	8.1221	0.4162	6.3001	0.3994	8-hour	2.17	0.00	2.17	2.35	0.00	2.35
					24-hour	1.09	0.00	1.09	1.24	0.00	1.24
					Annual	0.016	0.006	0.022	0.016	0.006	0.022
Vanadium	0.0686	0.0033	0.0532	0.0032	8-hour	0.018	0.000	0.018	0.020	0.000	0.020
					24-hour	0.0092	0.0000	0.0092	0.0106	0.0000	0.0106
					Annual	0.00014	0.00005	0.00019	0.00013	0.00005	0.00018
Zinc	0.6723	0.0325	0.5215	0.0311	8-hour	0.18	0.00	0.18	0.20	0.00	0.20
					24-hour	0.090	0.000	0.090	0.10	0.000	0.10
					Annual	0.0013	0.0005	0.0018	0.0013	0.0005	0.0018

Note: Impacts for arsenic, beryllium, ethanolamine, and sulfuric acid mist were predicted by modeling these pollutants at their actual emission rates. All other impacts presented were derived by using a ratio method based on the impacts predicted for beryllium.